Technical Study for Community Choice Energy Program in Contra Costa County

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List of Acronyms

AAEE	Additional Achievable Energy Efficiency
CAISO	California Independent System Operator
CBA	Collective Bargaining Agreement
CCA	Community Choice Aggregation
CCE	Community Choice Energy
CEC	California Energy Commission
CPUC	California Public Utilities Commission
EE	Energy Efficiency
EBCE	East Bay Community Energy
ESPs	Energy Service Providers
FY	Fiscal Year
GHG	Greenhouse Gas
GRP	Gross Regional Product
GWh	Gigawatt-hour (= 1,000 MWhs)
IOU	Investor-Owned Utility
I/T	Information Technology
JEDI	Jobs and Economic Impact (model)
JPA	Joint Powers Authority
kWh	Kilowatt-hour
MW	Megawatt
MWh	Megawatt-hour
NREL	National Renewable Energy Laboratory
PCIA	Power Charge Indifference Adjustment
PEIR	Programmatic Environmental Impact Report
PG&E	Pacific Gas & Electric
REC	Renewable Energy Credit
REMI	Regional Economic Modeling Inc
RPS	Renewable Portfolio Standard
SB 350	Senate Bill 350
TURN	The Utility Reform Network

Executive Summary

Main Findings

1. This study finds that the jurisdictions in Contra Costa County studied[1] in this report have several options for implementing a Community Choice Energy (CCE) program that would likely result in lower greenhouse gas (GHG) emissions, increased local renewable energy generation, and increased local job creation compared to remaining with current electricity service from the Pacific Gas and Electric Company (PG&E).

2. The electricity rates charged under various CCE scenarios available to the jurisdictions covered in this study would likely be similar or less than the rates charged by PG&E for comparable service. The degree to which CCE rates are reduced below comparable PG&E rates depends in large part on the extent to which the CCE pursues policy objectives other than rate minimization in its energy procurement practices. Competing policy objectives may include increasing the supply of locally generated renewable energy, promoting energy efficiency, and maximizing local employment generated from a CCE program.

3. This study finds that Contra Costa County includes enough technically feasible locations to meet a significant proportion of electricity demand for the area studied through locally generated renewable energy. Forty percent of the technically feasible sites fall within the Northern Waterfront Economic Development Initiative area.

4. The implementation of a CCE program within the studied area is projected to create between 500 and 700 new jobs within Contra Costa County compared to remaining with current PG&E service, depending on the CCE option implemented.

5. This study compares three CCE program alternatives to current PG&E service and identifies the tradeoffs associated with these four alternatives. The decision of which program alternative to implement will require policy makers to balance costs and potential risks and benefits of each option, which are described in detail.

Purpose of this Study

Community Choice Energy is described in State law as "Community Choice Aggregation." California Assembly Bill 117, passed in 2002, established Community Choice Aggregation in California to provide the opportunity for local governments or special jurisdictions to procure or provide electric power for their residents and businesses. On March 15, 2016, the Contra Costa County (County) Board of Supervisors directed County staff to work with cities within the County to obtain electrical load data from PG&E for conducting a technical study of options for

[1] The communities constituting the "Contra Costa CCE" throughout the report are Antioch, Brentwood, Clayton, Concord, Danville, Hercules, Martinez, Moraga, Oakley, Orinda, Pinole, Pittsburg, Pleasant Hill, San Ramon, and unincorporated County. They do not include those communities already being served by the Community Choice Aggregator, MCE (El Cerrito, Lafayette, Richmond, San Pablo, and Walnut Creek).

implementing CCE within the County's unincorporated area and the 14 cities within the County not currently participating in a CCE program. The Board of Supervisors further directed the CCE technical study to compare alternatives for implementing CCE (i.e., establishing a Contra Costa County-Only CCE or joining one of the neighboring CCEs – MCE, formerly Marin Clean Energy, or East Bay Community Energy) to the option of remaining with PG&E.

To assess whether a stand-alone CCE is "feasible" in Contra Costa County, the local objectives must be laid out and understood. Based on the specifications of the initial request for proposals and input from the County, this study:

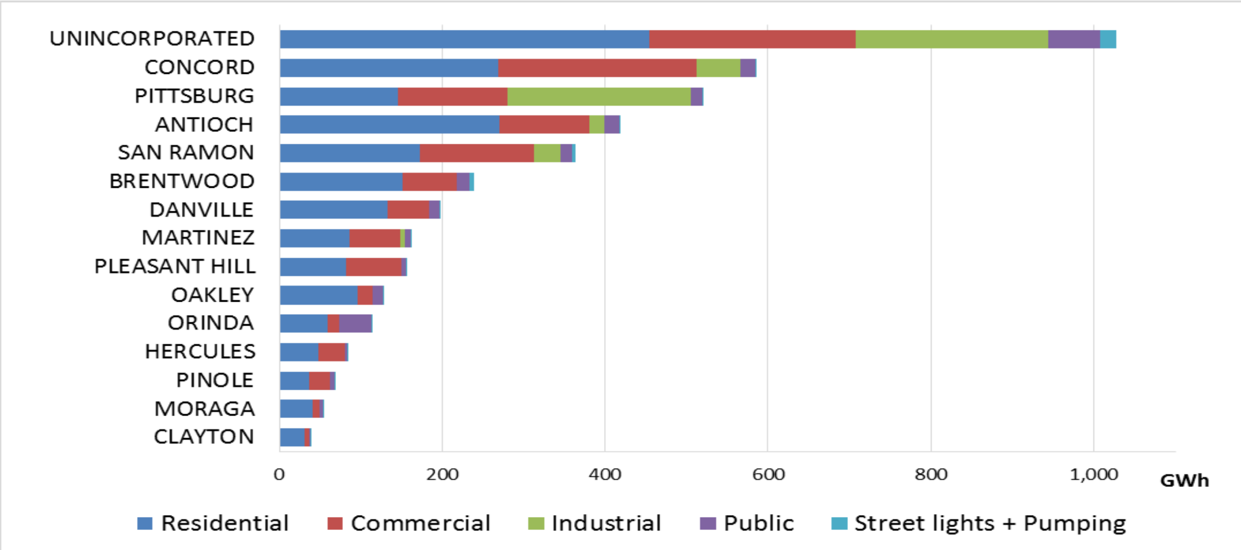
- Quantifies the electric loads that a Contra Costa County CCE would serve;
- Includes analysis of in-county renewable generation;
- Compares the rates that could be offered by the CCE to PG&E's rates;
- Calculates the macroeconomic development and employment benefits of CCE formation; and
- Compares the benefits and risks of forming a CCE or joining a neighboring CCE versus remaining on PG&E bundled service.

Loads and Forecast

Figure ES-1 provides a snapshot of Contra Costa County bundled electric load in 2015 by city and by rate class.[2] As the figure shows, total bundled electricity load in 2014 from Contra Costa County was approximately 4,000 GWh. The unincorporated areas of the County represented 25% of County load, and the cities of Concord and Pittsburg were together responsible for another 25%. Residential and commercial customers made up most the County load, with smaller contributions from the industrial and public sectors.

[2] "Bundled" load includes only load for which PG&E supplies the power; it excludes load from Direct Access customers, load in the jurisdiction of another CCE provider, and load met by customer self-generation. This excludes load originating in the cities of El Cerrito, Lafayette, Richmond, San Pablo, and Walnut Creek, which are served by MCE.

Figure ES-1. PG&E's 2015 Bundled Load in Contra Costa County



CCE Power Supplies

The CCE's primary function is to procure supplies to meet the electrical loads of its customers. By law, the CCE must also supply a certain portion of its sales to customers from eligible renewable resources. This Renewable Portfolio Standard (RPS) requires 33% renewable energy supply by 2020, increasing to 50% by 2030. The CCE may additionally choose to source a greater share of its supply from renewable sources than the minimum requirements, or may seek to otherwise reduce the environmental impact of its supply portfolio. The CCE may also use its procurement function to meet other objectives, such as sourcing a portion of its supply from local projects to promote economic development in the County. The four supply scenarios considered in this analysis are summarized in Table ES-1.

Table ES-1: Four Scenarios Modeled[3]

Scenario:	1	2	3	4
% RPS-Eligible in 2020	33%	50%	33%	50%
% RPS-Eligible in 2030	50%	80%	50%	80%
Share of RPS-Eligible from Local Resources	0%	0%	50%	50%

[3] Customer-sited solar is not considered RPS-eligible in California and is not included in the RPS procurement in these scenarios. Customer-sited solar is incorporated in this analysis as a reduction to the CCE's load.

Local Renewable Development

The CCE may choose to contract with or develop renewable projects within Contra Costa County to promote economic development or reap other benefits. This study found 1,395 parcels that met the established criteria and 1,875 individual sites within the identified parcels where either a solar shade structure, large rooftop, or ground mounted system could be developed. Table ES-2 shows the total solar PV generation capacity within the County based on the methodology and assumptions in Chapter 3.

Table ES-2. Total PV Solar Generation Potential and Build Cost

	Ground Mount	Shade Structure	Roof Mounted	Total
PV Capacity (MW)	1,891	1,320	144	3,355
PV Production (GWh)	3,025	2,113	230	5,369
Build Cost ($ Millions)	$3,417	$3,977	$371	$7,660
Build Cost ($/Watt)	$1.99	$3.10	$2.62	$2.56
No of PV Systems	845	886	144	1,875

CCE Rate Analysis Results

Scenarios 1 and 3 (Simple Renewable Compliance)

In Scenario 1, the CCE meets the mandated 33% RPS requirement in 2020 and the 50% RPS requirement in 2030, plus the 55% proposed target between 2030 and 2038. Annual GHG emissions are 50% lower on average than PG&E's forecasted annual GHG emissions by assuming a fraction of the non-RPS power is provided by large hydroelectric resources.

Figure ES-2 summarizes the results of Scenario 1. The figure shows the total average cost of the Contra Costa County CCE to serve its customers (vertical bars) and the comparable PG&E generation rate (line).[4] Of the CCE cost elements, the greatest cost is for non-renewable generation (including large hydroelectric), followed by the cost for renewable generation, which increases over the years per the RPS requirements. Another important CCE customer cost is the Power Charge Indifference Adjustment (PCIA), which is the mandated charge that State regulators require PG&E to impose on all CCE customers.[5]

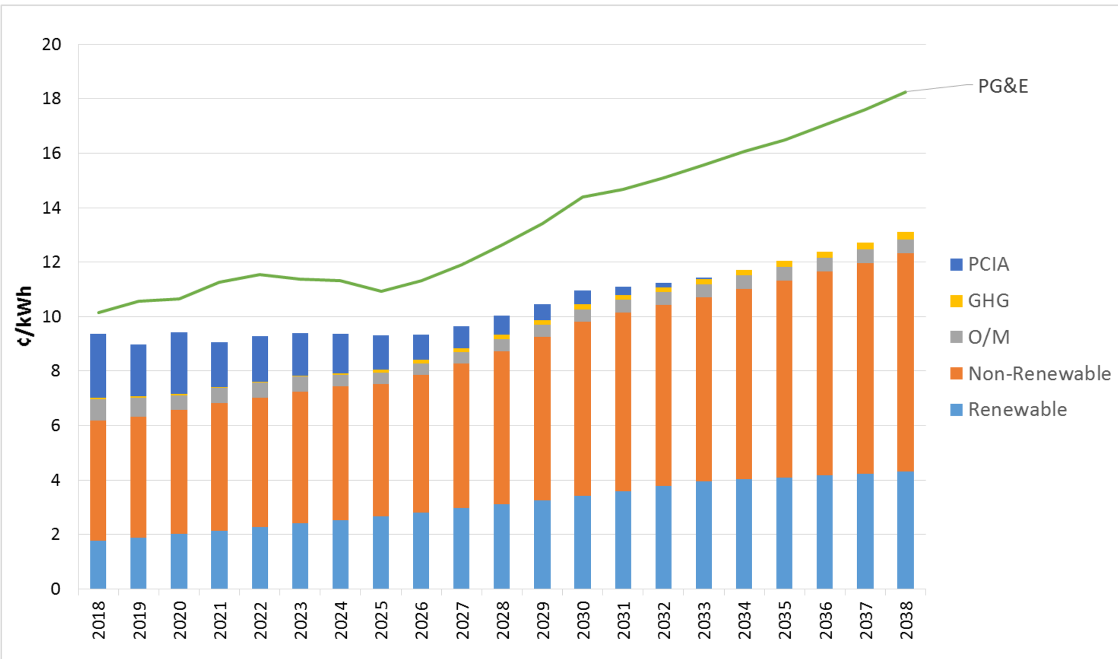
[4] All rates are in nominal dollars. Note that these are NOT the full rates shown on PG&E bills. They are only the generation portion of the rates. Other parts of the rate, such as transmission and distribution, are not included, as customers pay the same charges for these components regardless of who is providing their power.

[5] Per current regulations, the PCIA fee is expected to decrease in most years beginning in 2019 and to have less of an impact on CCE customer rates over time as resources expire from PCIA eligibility for CCE customers. However, given that PCIA regulations are subject to change, the possibility that PCIA rates may not decrease as expected is considered in the High PCIA scenario.

Under Scenario 1, the differential between PG&E generation rates and the average cost for the Contra Costa County CCE to serve its customers (*aka* the CCE rates) is positive in each year (i.e., CCE rates are lower than PG&E rates). As a result, Contra Costa County CCE customers' average generation rate (including contributions to the CCE's reserve fund) can be set at a level that is lower than PG&E's average customer generation rate in each year.

Scenario 3 is the same as Scenario 1 except that by 2028 one-half of the renewable power is provided by local resources. The differential between PG&E generation rates and Contra Costa County CCE customer rates in Scenario 3 is lower than in Scenario 1; the expected Contra Costa County CCE rates continue to be lower than the forecast PG&E generation rates for all years from 2018 to 2038.

Figure ES-2. Scenario 1 Forecast Average CCE Cost and PG&E Rates, 2018-2038



Scenarios 2 and 4 (Accelerated RPS)

Under Scenario 2, the Contra Costa County CCE starts with 50% of its load being served by renewable sources in 2017, and increases this at a quick pace to 80% renewable energy content by 2030. Scenario 4 is the same as Scenario 2 except that by 2027 one-half of the renewable power is provided by local resources.

The differential between PG&E generation rates and Contra Costa County CCE customer rates in Scenarios 2[6] and 4 is narrower than in Scenarios 1 and 3. Still, the expected Contra Costa County CCE rates continue to be lower on average than the forecast PG&E generation rates for all years from 2018 to 2038. However, for Scenario 4—very high local renewable penetration—

[6] After 2033, the Contra Costa County CCE rates are lower for Scenario 2 than Scenario 1.

the modeling suggests that the CCE might not be able to beat PG&E rates in the 2025-2030 timeframe. (See Chapter 3 for details).

Greenhouse Gas Emissions

Under Scenarios 1 and 3, we include enough GHG-free hydroelectric power so that the Contra Costa County CCE's GHG emissions rate is about half of PG&E's GHG emissions rate. This requires using large hydroelectric power for 35% of the CCE's generation portfolio, on average, from 2018 to 2038. Though this large hydroelectric power would not qualify for RPS requirements, it is considered a non-GHG emitting resource.[7] Under Scenarios 2 and 4 these additions of large hydro power are not needed once the high renewable targets are met. The result is a portfolio that averages 20% large hydro from 2018 to 2038.

Tables ES-4 shows GHG emissions from 2018-2038 for the Contra Costa County CCE in each Scenario and what PG&E's emissions would be for the same load if no CCE were formed. Overall, the CCE is projected to reduce GHG emissions from the County by about half. This result is due in large part to not only the assumed renewable generation, but also the hydroelectric power assumed to be part of the CCE's supply mix.

Note that the analysis assumes "normal" hydroelectric output for PG&E. During the drought years, PG&E's hydro output has been at about 50% of normal, and the utility has made up these lost megawatt-hours through additional gas generation. This means that the "normal" PG&E emissions shown here are lower than the "current" emissions. If, as is expected by many experts, the recent drought conditions are closer to the "new normal", then PG&E's GHG emissions in the first 8 years would be approximately 30% higher. Depending on whether the CCE were similarly affected by limited hydroelectric supply, the CCE's emissions may increase as well.

Table ES-4. Comparative GHG total emissions for PG&E and Contra Costa CCE

GHG emissions	PG&E (KTonnes)[8]	Contra Costa CCE (KTonnes)	Savings (%)
Scenario 1	5,882	2,957	50%
Scenario 2	5,882	2,693	54%
Scenario 3	5,882	2,957	50%
Scenario 4	5,882	2,693	54%

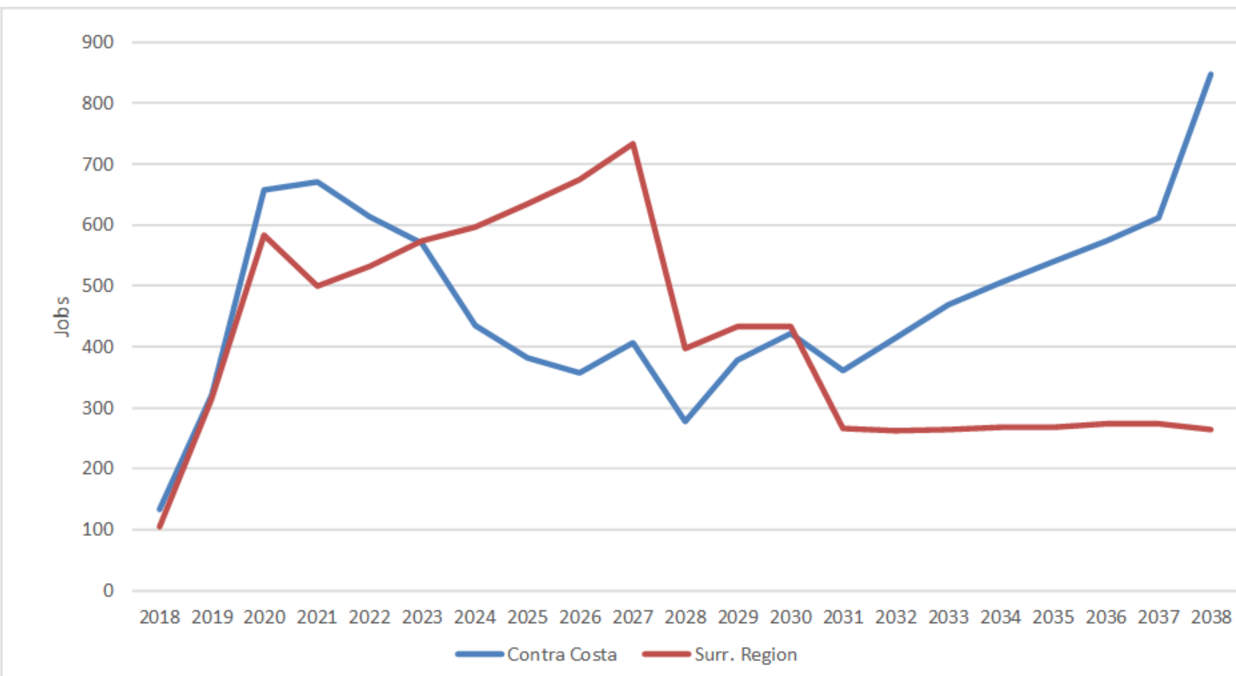
[7] While there is a limited supply of uncontracted large hydroelectric power, other operating CCEs have been successful in procuring this resource. To account for the limited supply, we added a 10% premium to the cost of this power.
[8] Thousands of metric tons.

Macroeconomic and Job Impacts

The local economic development and jobs impacts for the four scenarios were analyzed using the dynamic input-output macroeconomic model developed by Regional Economic Models, Inc. (REMI). The model accounts for not only the impact of direct CCE activities (e.g., local project installations for two of the four scenarios, program administration), but also how the rate savings that County households and businesses might experience with a CCE ripple through the local economy, creating more jobs and regional economic growth.

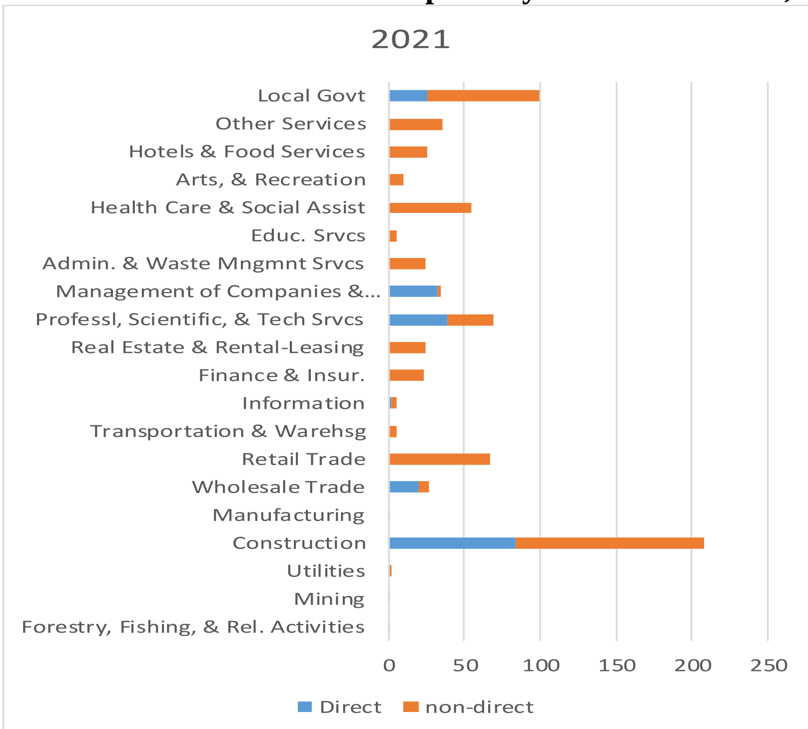
A CCE can also offer positive economic development and employment benefits to the County. The CCE could create approximately 500 to 700 additional annual jobs on average in the County plus an additional 50 to 400 jobs in the neighboring counties, depending on the scenario. The job impacts include not just the stimulus from program-related effects but jobs resulting from *multiplier effects* and *competitiveness effects.* Scenario 4 – with the smallest of *net* rate savings for the County's electric customers contains the largest investment for small solar across the local economy. Figure ES-3 illustrates this through high-level results expressed as annual job changes for the Scenario 4.

Figure ES-3. Scenario 4 Regional Annual Jobs Impacts, 2018 to 2038



The economic activity generated by the CCE results in incremental employment in a variety of sectors. Figure ES-4 shows the estimated job impacts (direct and indirect) by sector for Scenario 4 in 2021 (the year in which the CCE's assumed solar investment is maximum).

Figure ES-4. Contra Costa Job Impacts by Sector Scenario 4, 2021



Comparative Analysis of CCE Options

Having the County and cities within the County form their own Joint Powers Authority (JPA) and CCE Program is not the only possibility for CCE participation. First, the County and/or its cities may join MCE (formerly Marin Clean Energy). In fact, five cities in the County—El Cerrito, Lafayette, Richmond, San Pablo, and Walnut Creek—are already members of MCE. These cities joined between 2012 and 2016, and have full standing on MCE's board of directors. Second, the County and/or its cities could join East Bay Community Energy (Alameda County, EBCE). While this CCE has just been formed—the JPA board met for the first time in January 2017—it intends to begin delivery of power in early 2018. Furthermore, the County and each city need not join one or the other CCE *en masse,* but instead can join one or the other CCEs individually (or neither).

Table ES-5 below provides a qualitative summary of the differences and similarities among these options. While a quantitative comparison would appear to provide more rigor, in this case it would provide only false precision. First and foremost, two of the potential CCE options are with entities which, while potentially viable, do not yet exist. Without power contracts, portfolios, or procurement guidelines and policies, it would be unwise to claim that EBCE or a potential Contra Costa-only CCE would have rates or greenhouse gas emissions higher or lower than the other. Comparisons against MCE can be somewhat more reasonably asserted; however, MCE's stated goals—greater renewable energy content, lower greenhouse gas emissions, local generation, and comparable rates—are nearly identical to those stated by EBCE, making long-range rate and emissions distinctions immaterial. Thus, the qualitative comparisons provided in the table do not provide sharp distinctions between the CCE options.[9] All these options are expected to provide similar rates and GHG emissions, with differences arising from variations in the priorities and procurement decisions of the individual governance boards. What truly distinguishes these options are primarily governance options (i.e., in-county only versus shared with other entities) and the amount of risk assumed (i.e., developing or signing on with a new CCE versus joining one with a record of satisfactory performance).

Table ES-5. Comparison of Contra Costa CCE Options

Criterion	Form CCCo JPA	Join MCE	Join EBCE	Stay with PG&E
Rates	Likely lower	Likely Lower	Likely Lower	Base
GHG Reduction Potential Over Forecast Period	Some	Some	Some	Base
Local Control/Governance	Greatest	Some	Some	None
Local Economic Benefit Potential	Greatest	Some	Some	Minimal
Start Up Costs/Cost to Join	Low, but greater risk[10]	None	None	None
Level of Effort	Greatest	Minimal	Greater	None
Program Risks	Greatest	Minimal	Some	Base
Timing (earliest)	Late-2018	Late-2017	Mid-2018	N/A

[9] Differences between the CCE options and the option to stay with PG&E are more marked and better quantifiable, given that information on PG&E's power portfolios, procurement plans, and costs are at least partially available through various filings and applications PG&E has made before the CPUC. The comparisons provided above between the CCE's rates and PG&E's rates takes advantage of this information and market data on power procurement costs to develop quantitative comparisons between the CCE and PG&E options.

[10] Start-up costs incurred by the County or others are likely to be reimbursed by the JPA.

Conclusions

Overall, a CCE in Contra Costa County appears feasible. Given current and expected market and regulatory conditions, a Contra Costa County CCE should be able to offer its residents and businesses electric rates that are less than those available from PG&E.

Sensitivity analyses suggest that these results are relatively robust. Only when very high amounts of local renewable energy are assumed in the CCE portfolio, combined with other negative factors such as higher PCIA rates, higher prices for local renewable power, or lower PG&E costs, do PG&E's rates become consistently more favorable than the CCE's.

A Contra Costa County CCE would also be well positioned to help facilitate greater amounts of renewable generation to be installed in the County. Because the CCE would have a much greater interest in developing local solar than PG&E, it is much more likely that such development would occur with a CCE in the County than without it.

The CCE can also reduce the amount of greenhouse gases emitted in the County if the CCE prioritizes this goal. Because PG&E's supply portfolio has significant carbon-free generation (from large hydroelectric and nuclear generators), the CCE would need to contract for significant amounts of hydroelectric or other carbon-free power above and beyond the required qualifying renewables to reduce the County's GHG footprint from electricity use. This analysis assumes that the CCE procures enough GHG-free generation to halve PG&E's GHG emissions rate, subject to constraints on the minimum share of market supplies in the CCE portfolio.

A CCE can also offer positive economic development and employment benefits to the County. At the peak, the CCE could create approximately 500 to 700 new jobs in the County plus additional jobs in neighboring counties. What may be surprising is that many of the economic benefits can come from reduced rates: residents and, more importantly, businesses can spend and reinvest their bill savings, and thus generate greater economic impacts.

While the analytical focus of this report has been on a stand-alone Contra Costa County CCE, that is not the only choice for Contra Costa communities (not already in MCE). Overall, there is insufficient data to suggest that a stand-alone Contra Costa CCE would offer lower rates or greater GHG savings than joining MCE or EBCE. Either forming or joining a CCE would likely offer modestly lower rates, more local economic development, and similar or lower GHG emissions than remaining with PG&E. Joining MCE would likely result in the quickest and least risky path to CCE implementation, however at a loss of local input into CCE policy formation. Because it has yet to be formed, joining with EBCE would take longer than joining the already-established MCE, but would offer greater input into the CCE's policies and formation.

Although all the CCE program options available to the jurisdictions studied would likely provide both environmental and economic benefits compared to PG&E, continuing service from PG&E remains an option for not only a community but also for any individual or business whose community has selected CCE service. PG&E is an experienced power provider and is regulated by the State. Furthermore, remaining with PG&E does not require the jurisdiction to take any action. Lastly, simply because a Contra Costa community does not join a CCE in 2017 or 2018 does not necessarily preclude it from doing so in the future, although waiting may result in an "entry fee" or perhaps a higher PCIA rate.

Chapter 1: Introduction

On March 15, 2016, the Contra Costa County (County) Board of Supervisors directed County staff to work with cities within the County to obtain electrical load data from the Pacific Gas and Electric Company (PG&E) for the purpose of conducting a technical study of options for implementing Community Choice Energy (CCE) within the County's unincorporated area and the 14 cities within the County not currently participating in a CCE program. The Board of Supervisors further directed the CCE technical study to compare the following alternatives for implementing CCE to the option of remaining with current electrical service from PG&E:

1. Form a new Joint Powers Authority (JPA) of the County and interested cities within Contra Costa County for the purpose of CCE;

2. Form a new JPA in partnership with Alameda County and interested cities in both counties; and

3. Join the existing CCE program initiated in Marin County, known as Marin Clean Energy (MCE).

The County and the 14 Contra Costa cities not currently participating in a CCE program all authorized the collection of load data from PG&E for this technical study. In addition, the County and the cities of Brentwood, Clayton, Concord, Martinez, Pleasant Hill, Pittsburg, and San Ramon, and the Towns of Danville and Moraga, contributed funding for the completion of this study.

What is a CCE?

California Assembly Bill 117, passed in 2002, established Community Choice Aggregation (also known as Community Choice Energy or "CCE") in California, for the purpose of providing the opportunity for local governments or special jurisdictions to procure or provide electric power for their residents and businesses.

Under existing rules administered by the California Public Utilities Commission (CPUC), PG&E must use its transmission and distribution system to deliver the electricity supplied by a CCE in a non-discriminatory manner. That is, it must provide these delivery services at the same price and at the same level of reliability to customers taking their power from a CCE as it does for its own full-service customers. By state law, PG&E also must provide all metering and billing services such that customers receive a single electric bill each month from PG&E, which would differentiate the charges for generation services provided by the CCE from the charges for PG&E delivery services. Money collected by PG&E on behalf of the CCE must be remitted in a timely fashion (e.g., within 3 business days).

As a power provider, the CCE must abide by the rules and regulations placed on it by the State and its regulating agencies, such as maintaining demonstrably reliable supplies, fully cooperating with the State's power grid operator, and meeting renewable procurement requirements. However, the State has no rate-setting authority over the CCE; the CCE may set rates as it sees fit so as to best serve its constituent customers.

Per California law, when a CCE is formed all the electric customers within its boundaries will be placed, by default, onto CCE service. However, customers retain the right to return to PG&E service at will, subject to whatever administrative fees the CCE may choose to impose.

California currently has five active CCE Programs: MCE, serving Marin County and selected neighboring jurisdictions, including five cities in Contra Costa County; Sonoma Clean Power, serving Sonoma County; CleanPowerSF, serving San Francisco City and County; Peninsula Clean Energy, serving San Mateo County; and Lancaster Choice Energy, serving the City of Lancaster (Los Angeles County). Numerous other local governments are also investigating CCE formation, including Alameda County; Los Angeles County; Monterey Bay region; Santa Barbara, San Luis Obispo and Ventura Counties; ; the City of Davis and Yolo County; and Humboldt County to name a few.

Assessing CCE Feasibility

In order to assess whether a CCE is “feasible” in Contra Costa County, the local objectives must be laid out and understood. Based on the specifications of the initial request for proposals and input from the County, this study:

- Quantifies the electric loads that a Contra Costa County CCE would serve;
- Estimates the costs to start-up and operate the CCE;
- Considers four scenarios with differing assumptions concerning the amount of GHG-free power and local renewable power being supplied to the CCE so as to assess the costs, greenhouse gas emissions reductions, and local economic development opportunities possible with the CCE;
- Includes analysis of in-county renewable generation;
- Compares the rates that could be offered by the CCE to PG&E’s rates;
- Quantitatively explores the rate competitiveness of the four scenarios to key input variables, such as the cost of natural gas;
- Calculates the macroeconomic development and employment benefits of CCE formation; and
- Compares the benefits and risks of forming a CCE or joining a neighboring CCE versus remaining on PG&E bundled service.

For comparison, the differences in the results between this study and that conducted for Alameda County will be described and underlying reasons explained.

The communities constituting the “Contra Costa CCE” in this study are: Antioch, Brentwood, Clayton, Concord, Danville, Hercules, Martinez, Moraga, Oakley, Orinda, Pinole, Pittsburg, Pleasant Hill, San Ramon, and unincorporated County. They do not include the communities already being served by the Community Choice Energy provider MCE (El Cerrito, Lafayette, San Pablo, Richmond and Walnut Creek).

This study was conducted by MRW & Associates, LLC (MRW). MRW was assisted by Sage Renewables, which conducted the local renewable energy potential study, and by Economic Development Research Group, which conducted the macroeconomic and jobs analysis contained in the study.

This study is based on the best information available at the time of its preparation, using publicly available sources for all assumptions to provide an objective assessment regarding the prospects of CCE operation in the County. It is important to keep in mind that the findings and recommendations reflected herein are substantially influenced by current market conditions within the electric utility industry, which are subject to sudden and significant changes.

Chapter 2: Economic Study Methodology and Key Inputs

This Chapter summarizes the key inputs and methodologies used to evaluate the cost-effectiveness and cost-competitiveness of a Contra Costa CCE relative to PG&E under different scenarios.[11] It considers the regulatory requirements that a Contra Costa County CCE would need to meet (e.g., compliance with renewable portfolio standard (RPS) requirements), the resources that the County has available or could obtain to meet these requirements, and the PG&E rates against which the CCE would compete. It also describes the pro forma analysis methodology that is used to evaluate the financial feasibility of the CCE.

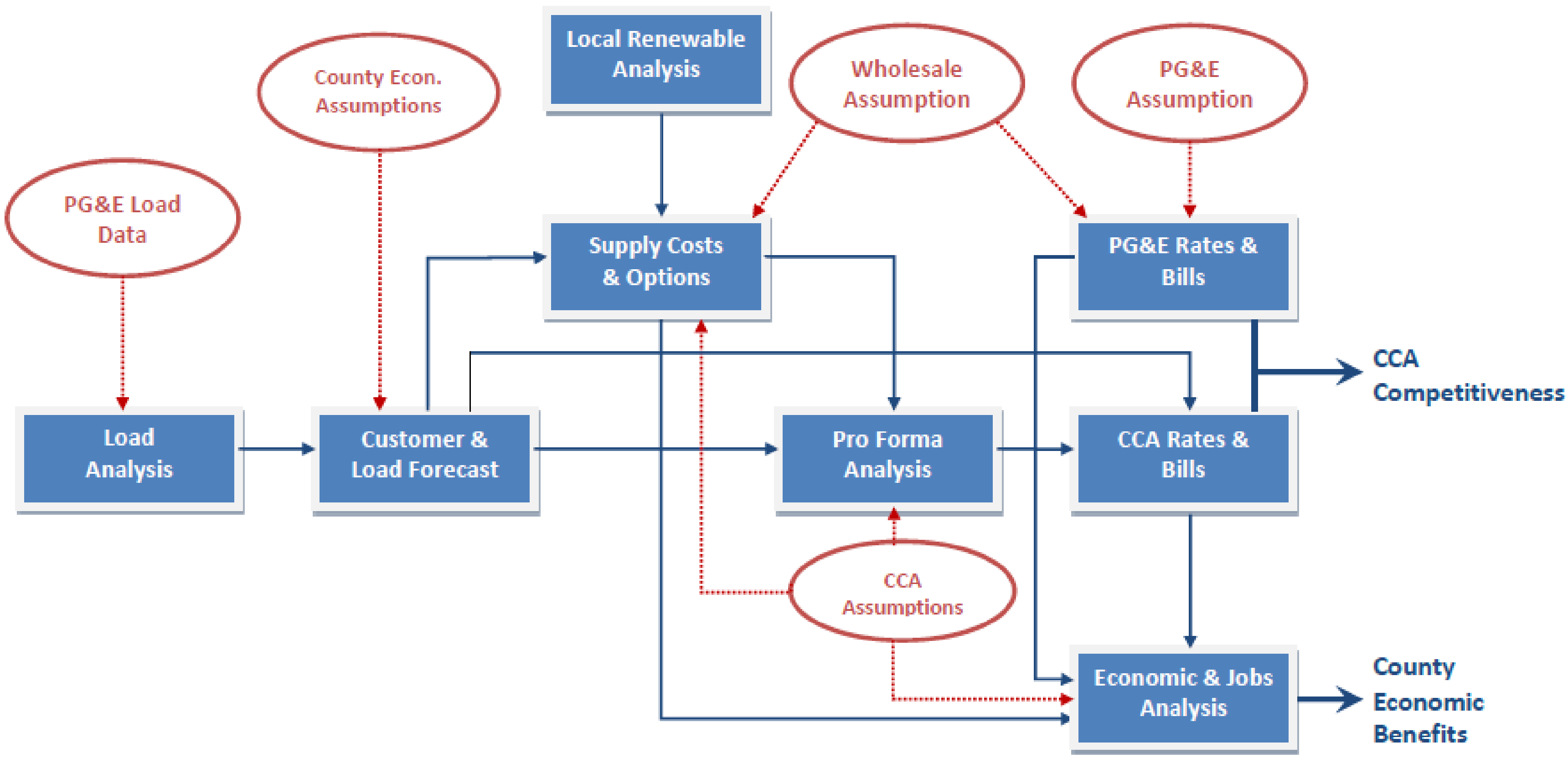
The load and rate forecasts go out twenty years—through 2038. While all forecasting contains an element of uncertainty, the years beyond 2030 are particularly uncertain and should be seen as broadly indicative and not predictive.

Understanding the interrelationships of all the tasks and using consistent and coherent assumptions throughout are critical to developing a meaningful analysis. Figure 1 shows the analysis elements (blue boxes) and major assumptions (red ovals) and how they relate to each other. As the figure illustrates, there are numerous interrelationships between the tasks. For example, the load forecast is a function of not only the load analysis, but also of projections of economic activity in the County.

Two important points are highlighted in this figure. First, it is critical that wholesale power market assumptions are consistent between the CCE and PG&E. While there are reasons that one might have lower or higher costs than the other for a particular product (e.g., CCEs can use tax-free debt to finance generation projects while PG&E cannot), both will participate in the wider Western U.S. gas and power markets and therefore will be subject to the same underlying market forces. Applying different power cost assumptions to the CCE than to PG&E, such as simply escalating PG&E rates while deriving the CCE rates using a bottom-up approach, would produce erroneous results. Second, virtually all elements of the analysis feed into the economic and jobs assessment. As is described in detail in Chapter 5, this Study uses a state-of-the art macroeconomic model that can account for numerous activities in the economy, which allows for a much more comprehensive—and accurate—assessment than a simple input-output model.

[11] The relative costs and merits of joining CCEs in neighboring counties are addressed in Chapter 7.)

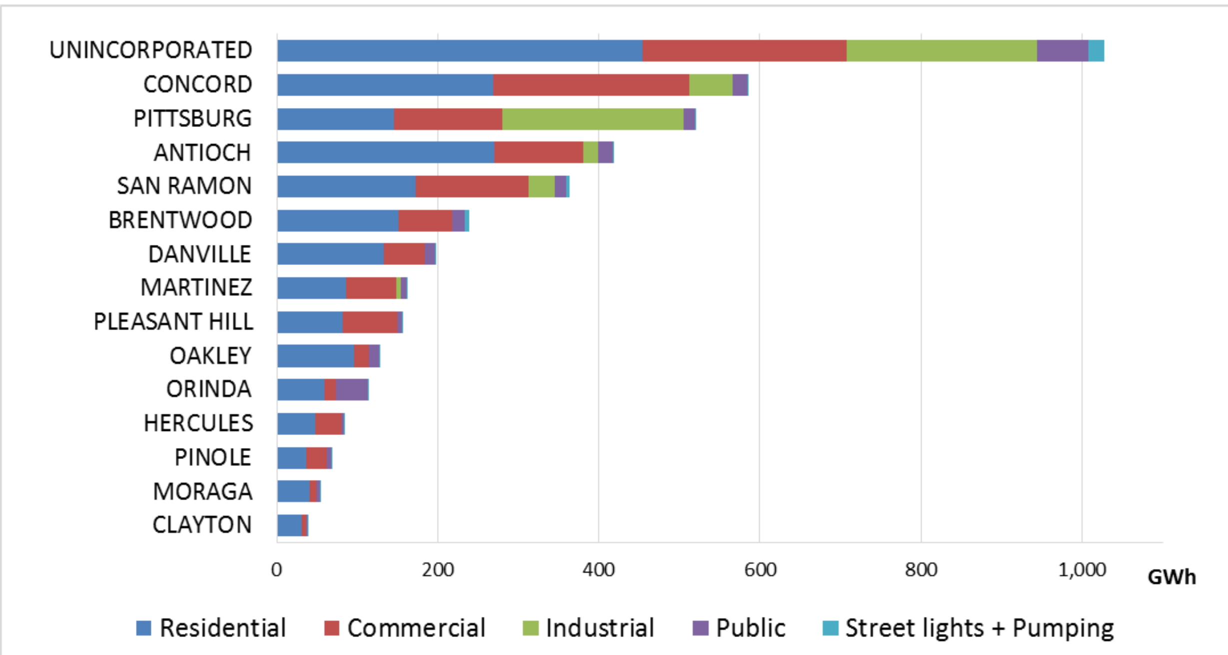
Figure 1. Task Map



Contra Costa County Loads and CCE Load Forecasts

MRW used PG&E bills from 2015 for all PG&E bundled service customers within the Contra Costa County region as the starting point for developing electrical load and peak demand forecasts for the Contra Costa County CCE program.[12] Figure 2 provides a snapshot of Contra Costa County bundled load in 2015 by city and by rate class. PG&E's total electricity load in 2015 from these customers was approximately 4,000 GWh.[13] The unincorporated areas of the County represented 25% of County load, and the cities of Concord and Pittsburg were together responsible for another 25%. Residential and commercial customers made up most of the County load, with smaller contributions from the industrial and public sectors (Figure 3). This same sector-level distribution of load is also apparent at the jurisdictional level for most cities (Figure 2), except for the City of Pittsburg, which has a significant industrial-sector footprint.

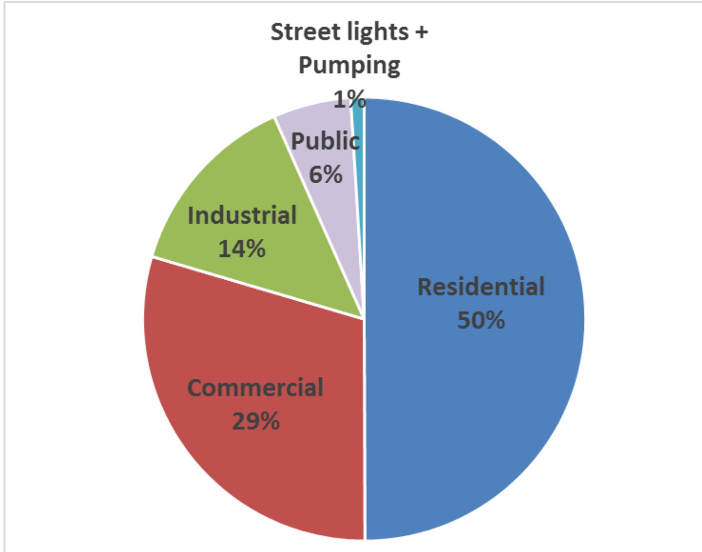
Figure 2. PG&E's 2015 Bundled Load in Contra Costa County by Jurisdiction and Rate Class



[12] Detailed monthly usage data provided by PG&E to Contra Costa County. "Bundled" load includes only load for which PG&E supplies the power; it excludes load from Direct Access customers, load in the jurisdiction of another CCE provider, and load met by customer self-generation. This excludes load originating in the cities of El Cerrito, Lafayette, Richmond, San Pablo, and Walnut Creek, which are served by MCE.

[13] As determined from bill data provided by PG&E.

Figure 3. PG&E's 2015 Bundled Load in Contra Costa County by Rate Class



To estimate CCE loads from PG&E's 2015 bundled loads, MRW assumed a CCE participation rate of 85% (i.e., 15% of customers opt to stay with PG&E) and a three-year phase in period from 2018 to 2020, with 33% of potential CCE load included in the CCE in 2018, 67% in 2019, and 100% in 2020. To forecast CCE loads through 2038, MRW used a 0.4% annual average growth rate, consistent with the California Energy Commission's most recent electricity demand forecast for PG&E's planning area.[14] The CCE load forecast is summarized in Figure 4, which shows annual projected CCE loads by class.

To estimate the CCE's peak demand in 2015,[15] MRW multiplied the load forecast for each customer class by PG&E's 2015 hourly ratio of peak demand to load for that customer class.[16] MRW extended the peak demand forecast to 2038 using the same growth rates used for the load forecast. The peak demand forecast is summarized in Figure 5.

[14] California Energy Commission. Form 1.1c California Energy Demand Updated Forecast, 2015 - 2025, Mid Demand Baseline Case, Mid AAEE Savings. January 20, 2015 http://www.energy.ca.gov/2014_energypolicy/documents/demand_forecast_cmf/LSE_and_BA/

[15] Peak demand is the maximum amount of power the CCE would use at any time during the year. It is measured in megawatts (MW). The CCE must have enough power plants on (or contracted with) at all times to meet 115% of the expected peak demand.

[16] Data obtained from PG&E's dynamic load profiles for Public, Industrial, Commercial, and Residential customers (https://www.pge.com/nots/rates/tariffs/energy_use_prices.shtml) and static load profiles for Pumping and Streetlight customers (https://www.pge.com/nots/rates/2016_static.shtml#topic2).

Figure 4: CCE Load Forecast by Class, 2018-2038[17]

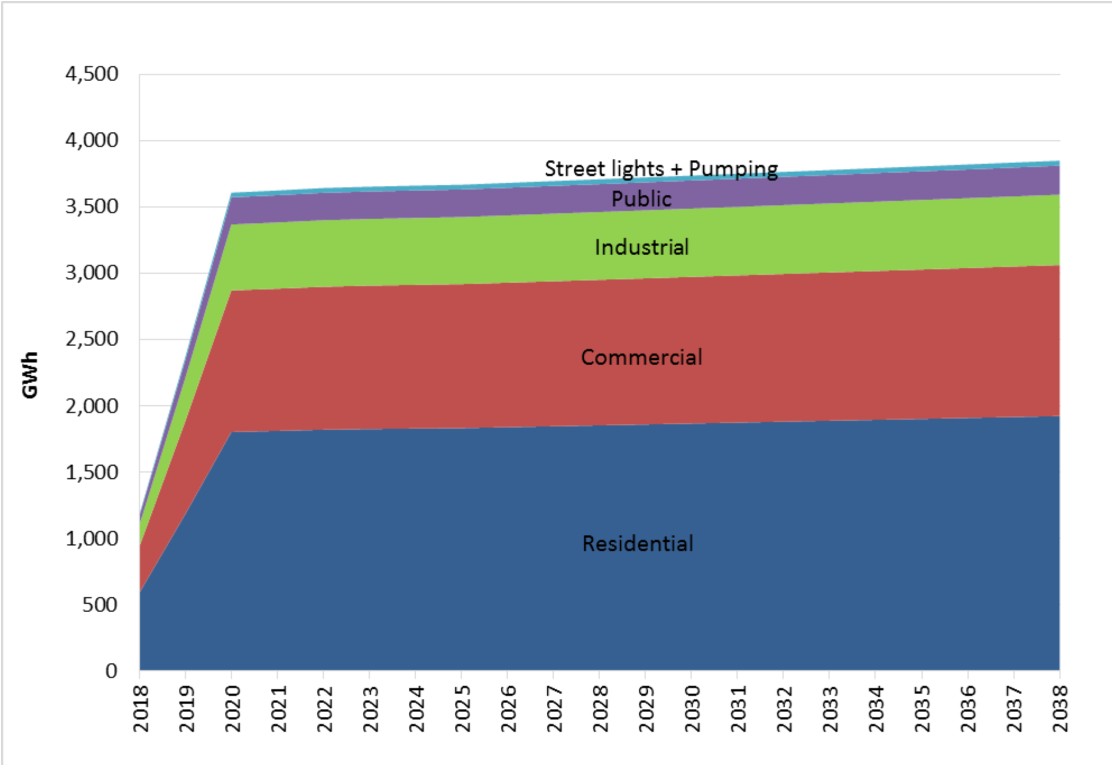
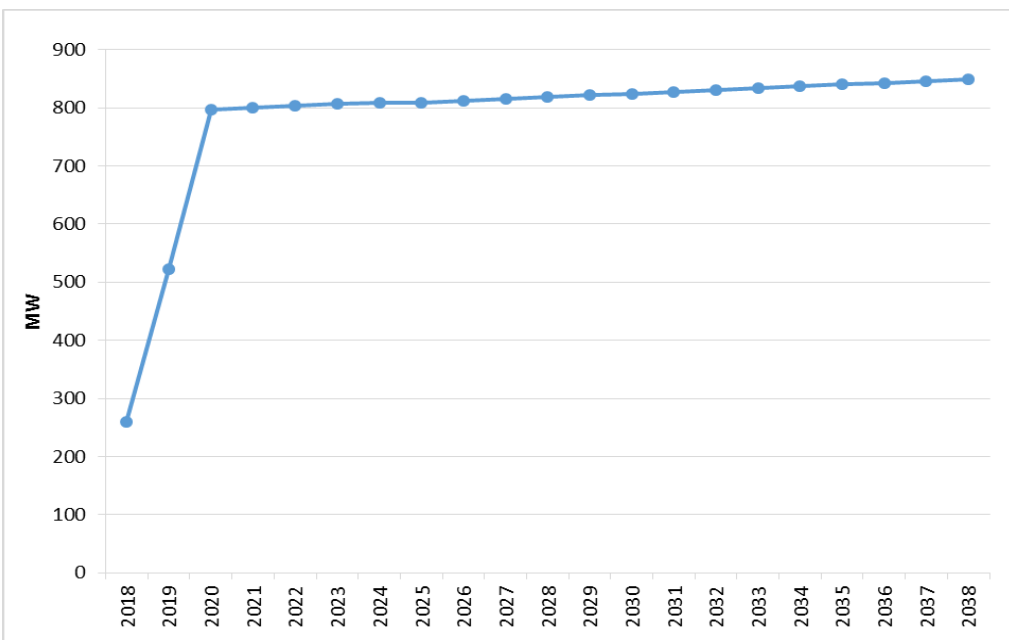


Figure 5. CCE Peak Demand Forecast, 2017-2038



17 Load forecasted assumes 85% participation and three-year phase-in.

CCE Supplies

The CCE's primary function is to procure supplies to meet the electrical loads of its customers. This requires balancing energy supply and demand on an hourly basis. It also requires procuring generating capacity (i.e., the ability to provide energy when needed) to ensure that customer loads can be met reliably.[18] In addition to meeting the energy and capacity needs of its customers, the CCE must meet other procurement objectives. By law, the CCE must supply a certain portion of its sales to customers from eligible renewable resources. This Renewable Portfolio Standard (RPS) requires 33% renewable energy supply by 2020, increasing incrementally to 50% by 2030. According to PG&E's Diablo Canyon nuclear plant retirement application, PG&E may commit to purchasing additional renewable supply, targeting up to 55% of the total generation between 2030 and 2038, which the CCE would presumably at least match. The CCE may additionally choose to source a greater share of its supply from renewable sources than the minimum requirements, or may seek to otherwise reduce the environmental impact of its supply portfolio. The CCE may also use its procurement function to meet other objectives, such as sourcing a portion of its supply from local projects to promote economic development in the County.

The Contra Costa County CCE would be taking over these procurement responsibilities from PG&E for those customers who do not opt out of the CCE to remain bundled customers of PG&E. To retain customers, the CCE's offerings and rates must compete favorably with those of PG&E.

The CCE's specific procurement objectives, and its strategy for meeting those objectives, will be determined by the CCE through an implementation plan, startup activities, and ongoing management of the CCE. A primary purpose of this portion of the study is to assess the feasibility of establishing a CCE to serve Contra Costa County based on a forecast of costs and benefits. This forecast requires making certain assumptions about how the CCE will operate and the objectives it will pursue. To address the uncertainty associated with these assumptions, we have evaluated four different supply scenarios and have generally made conservative assumptions about the ways in which the CCE would meet the objectives discussed above. In no way does this study prescribe actions to be taken by the CCE should one be established.

The four supply scenarios that we considered in this analysis are summarized in Table 1 and are described as follows:

1. **Minimum RPS Compliance:** The CCE meets the mandated 33% RPS requirement in 2020 and the 50% RPS requirement in 2030, plus the 55% RPS target after 2030. Annual GHG emissions from the CCE portfolio are halved relative to PG&E's bundled portfolio

[18] The California Public Utilities Commission requires that CCEs and other load serving entities demonstrate that they have procured resource adequacy capacity to meet at least 115% of their expected peak load. Because Contra Costa County falls within the Greater Bay Area Local Reliability Area, the Contra Costa County CCE must also meet its share of local resource adequacy requirements.

through the addition of large hydroelectric power purchases, subject to a constraint that 5% of the CCE supply come from non-renewable market sources.[19,20]

2. **Accelerated RPS:** The CCE's supply portfolio is set at 50% RPS in the first year and increases to 80% RPS by 2030. As in Scenario 1, the remaining supply is a mix of hydroelectric power and market purchases aimed at halving PG&E's annual emissions subject to a 5% minimum supply from market purchases.

3. **Minimum RPS Compliance plus Local:** The CCE meets the mandated 33% RPS requirement in 2020 and the 50% RPS requirement in 2030, plus the 55% RPS target after 2030. In addition, 50% of the total RPS generation is provided by local resources by 2030. Large hydroelectric and market supplies, and thus GHG emissions, are the same as in Scenario 1.

4. **Accelerated RPS plus Local:** The CCE's supply portfolio is set at 50% RPS in the first year and increases to 80% RPS by 2030. In addition, 50% of the total RPS generation is provided by local resources by 2030. Large hydroelectric and market supplies, and thus GHG emissions, are the same as in Scenario 2.

Table 1: RPS-Eligible Procurement and GHG Emissions in Each Scenario[21]

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Percent RPS-Eligible in 2020	33%	50%	33%	50%
Percent RPS-Eligible in 2030	50%	80%	50%	80%
Share of RPS-Eligible from Local Resources	0%	0%	50%	50%
GHG Emissions compared to PG&E	50% Lower	54% Lower	50% Lower	54% Lower

[19] For all scenarios we assume a minimum 5% non-renewable market supply to reflect operating constraints that require flexible, dispatchable generation on the system and in local areas. The CCE may be able to reduce emissions further through the use of energy storage or other measures to reduce the need for non-renewable power supplies, likely at additional cost.
[20] The availability and cost risks of large hydropower are discussed in Chapter 6, Impact of High CCE Penetration on Low-Carbon (Hydro) Resources.
[21] Customer-sited solar is not considered RPS-eligible in California and is not included in the RPS procurement in these scenarios. Customer-sited solar is incorporated in this analysis as a reduction to the CCE's load.

To evaluate these scenarios, we assumed a simple portfolio consisting of RPS-eligible resources and additional GHG-free resources in an amount dictated by the particular scenario, with the balance of supply provided by non-renewable wholesale market purchases. In each case, we assumed that the RPS portfolio was predominately supplied with solar and wind resources, which are currently the low-cost sources of renewable energy. We assumed that solar and wind each contribute 45% of the renewable energy supply on an annual basis. To provide resource diversity and partly address the need for supply at times when solar and wind production are low, we assumed the remaining 10% of renewable supply would be provided by higher-cost baseload renewable resources, such as geothermal or biomass.

In the early years, the CCE would have to purchase its required renewable power from the market and existing resources. However, the study assumes that the CCE would contract with new renewable resources, such that by 2030 most of its renewable power would come from new resources. Figures 6 and 7 show the assumed build-out of these new resources under the first (Minimum RPS Compliance) and the fourth (Accelerated RPS plus Local) scenarios described above.

Figure 6. Scenario 1 CCE Build-Out

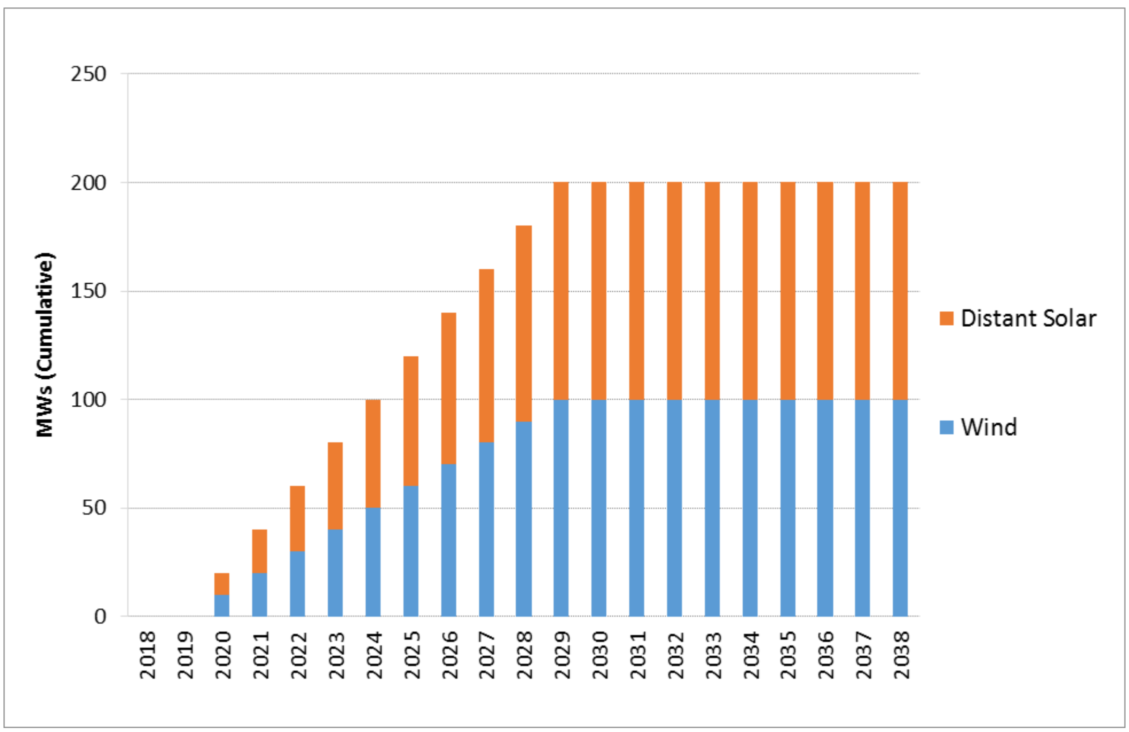
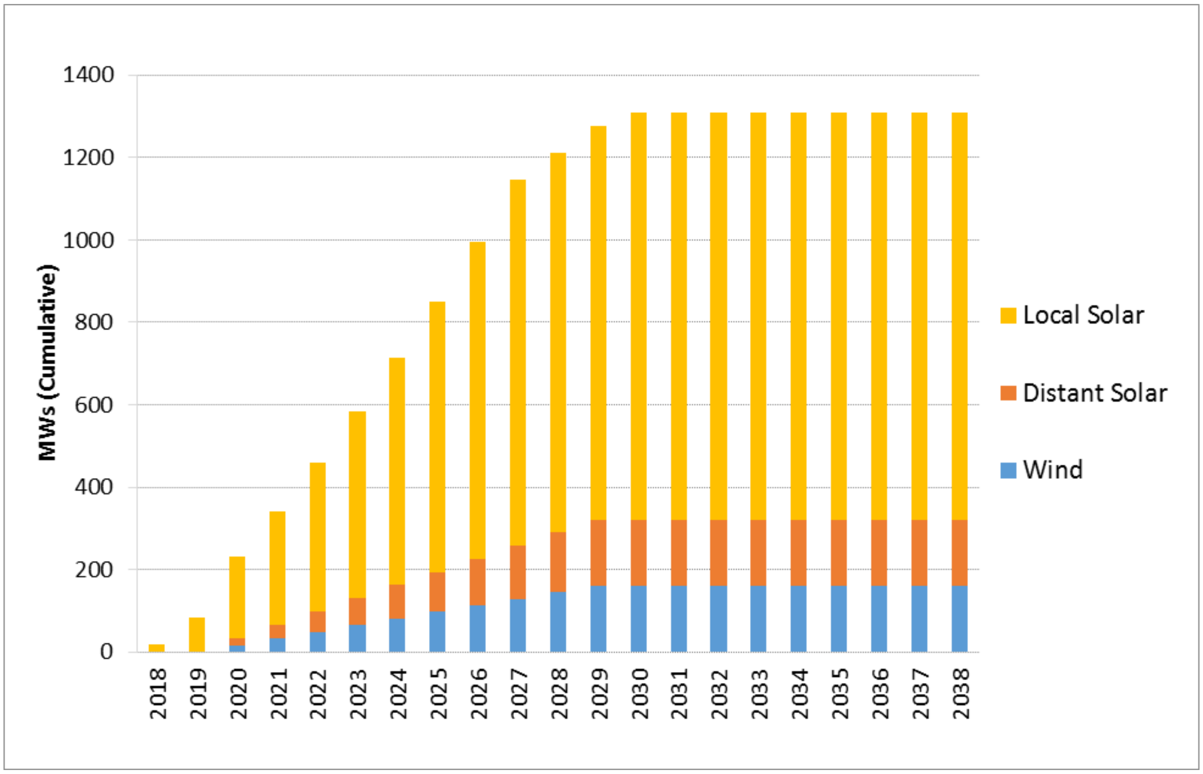


Figure 7. Scenario 4 CCE Build-Out

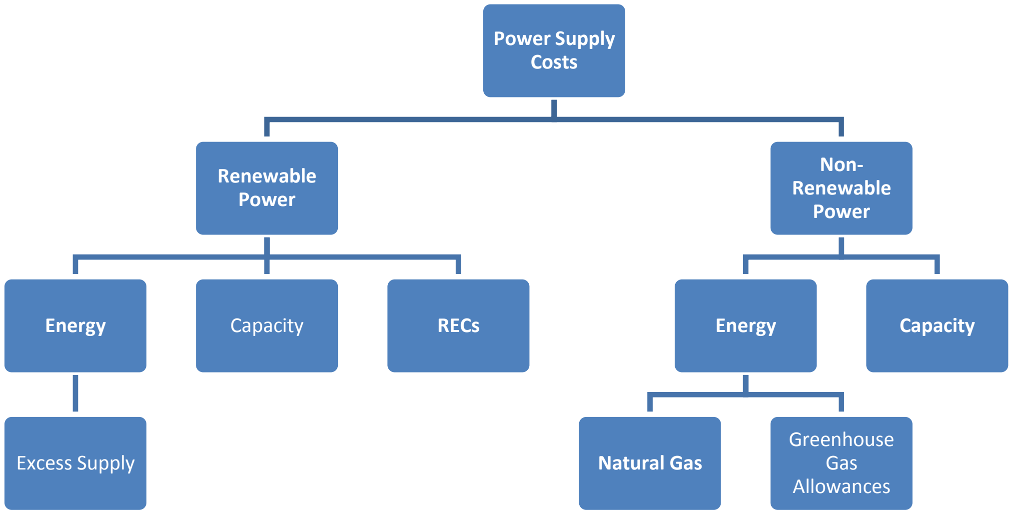


Power Supply Cost Assumptions

As discussed above, the CCE would procure a portfolio of resources to meet its customers' needs, which would consist of a mix of renewable and non-renewable (i.e., wholesale market) resources. As shown in Figure 8, the products to be purchased by the CCE consist generally of energy, capacity, and renewable attributes (which for counting purposes take the form of renewable energy credits, or Category 1 RECs).[22]

[22] RECs are typically bundled with energy deliveries from renewable energy projects, with each REC representing 1 MWh of renewable energy. A limited number of unbundled RECs may be used to meet RPS requirements. For the purpose of this study we have not considered unbundled RECs and have rather estimated costs based on renewable energy contracts where the RECs are bundled.

Figure 8. Power Supply Cost Elements



The CCE will procure supplies from the same competitive market for resources as PG&E. Thus, we assume that the costs for renewable and non-renewable energy and for resource adequacy (RA) capacity for the CCE are the same as for new purchases made by PG&E (discussed further in our forecast of PG&E rates). Wholesale market prices for electricity in California are largely driven by the cost of operating natural gas power plants, as these plants typically have the highest operating costs and are the marginal units. Market prices are a function of the efficiency of the marginal generators, the price of natural gas, and the cost of GHG allowances. MRW developed forecasts of these elements to derive a power price forecast to determine costs for the CCE and PG&E. Large hydroelectric power prices are based on the market price forecast with a 10% premium to reflect the value of GHG benefits, flexibility, and increasing demand from load serving entities seeking clean power like the CCE. Capacity prices are based on prices for RA contracts reported by the CPUC and on the cost to build a new combustion turbine power plant.

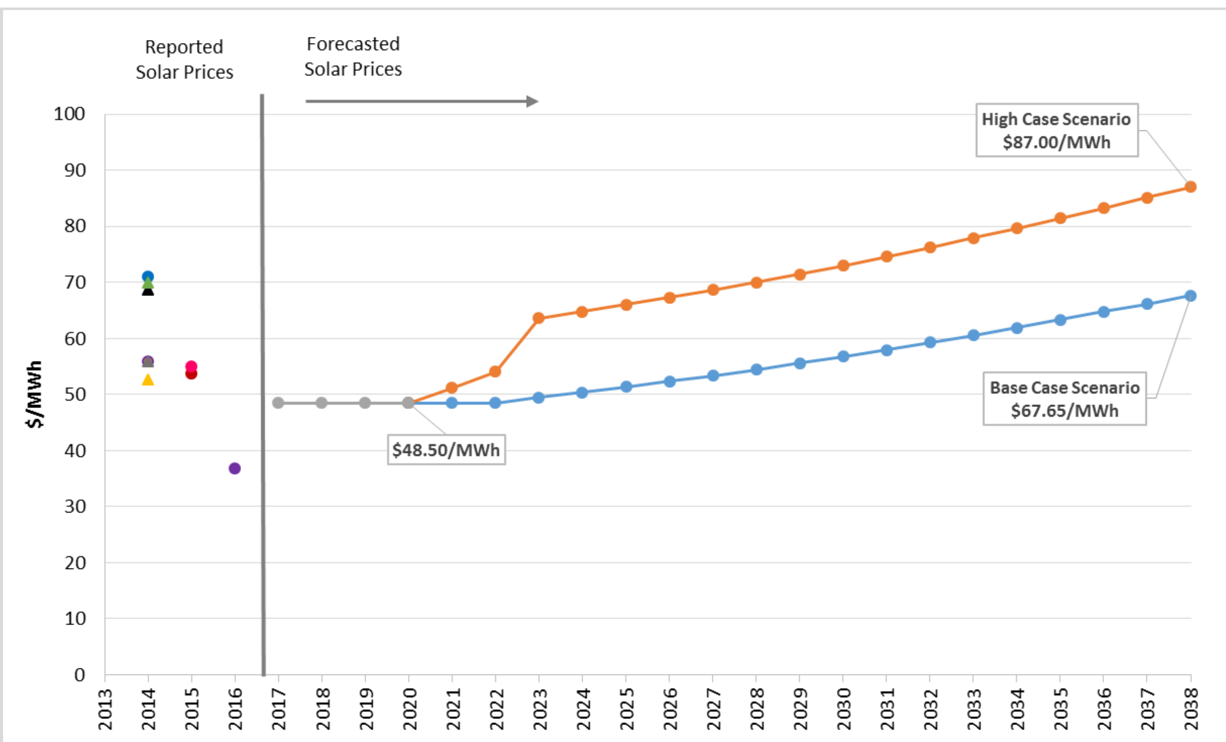
MRW developed a forecast of non-local utility scale renewable generation prices starting from an assessment of the current market price for renewable power. For the current market price, MRW relied on wind and solar contract prices reported by California municipal utilities and CCEs in 2015 and early 2016, finding an average price of $49/MWh for the solar contracts, $55/MWh for wind power and $80/MWh for geothermal.[23] We used these prices as the starting point for our forecast of CCE renewable energy procurement costs. For geothermal, which is a

[23] MRW relied exclusively on prices from municipal utilities and CCEs because investor-owned utility contract prices from this period are not yet public. We included all reported wind and solar power purchase agreements, excluding local builds (which generally come at a price premium), as reported in *California Energy Markets*, an independent news service from Energy Newsdata, from January 2015-January 2016 (see issues dated July 31, August 14, October 16, October 30, 2015, and January 15, 2016).

relatively mature technology, we assumed that new contract prices would simply escalate with inflation.

Solar and wind prices are a function of technology costs, which have generally been declining over time; financing costs, which have been very low in recent years; and tax incentives, which significantly reduce project costs, but phase out over time. In the near-term we would not expect prices to increase as technology costs and continued tax incentives provide downward pressure and likely offset any increase in financing costs or other competitive pressure from an increasing demand for renewable energy in California. For utility scale wind prices, we relied on an expert elicitation survey[24] developed by Lawrence Berkeley National Laboratory (LBNL). According to this survey, wind prices will decrease 24% by 2030 and 35% by 2050.[25] For solar, we held prices constant in nominal dollars through 2020. Beyond 2020, with increasing competitive pressure due to the drive to a 50% RPS and the anticipated phase-out of federal tax incentives (offset in part by declining technology costs), we would expect prices to increase somewhat and have assumed they escalate at the rate of inflation. In addition, we also considered a high solar cost scenario based on work performed by LBNL on the value of tax incentives. In the high scenario, we assume that costs increase with the phase-out of federal tax incentives, without being offset by declining technology costs. Figure 9 shows the resulting solar price forecasts for the two scenarios.

Figure 9. Large-Scale Non-Local Solar Price Forecast



[24] "Expert Elicitation Survey of Future Wind and Energy Costs," *Nature Energy*, September 12, 2016.
[25] Relative to the 2014 wind prices. MRW also added the annual inflation increase.

Local Solar Analysis

Pivotal to the evaluation of the local economic impacts of a Contra Costa CCE is an understanding of how much renewable energy can be developed within the County. This assessment focused on identifying local solar photovoltaic (PV) siting potential. Wind and biomass energy were also evaluated, but were determined to be less feasible for Contra Costa County.

The solar PV assessment is based on a comprehensive desktop review of countywide parcel data, geographic features, and solar energy potential. Table 2 shows the total solar PV generation capacity within the County based on the methodology and assumptions described below.

Table 2. Total PV Solar Generation Potential and Build Cost

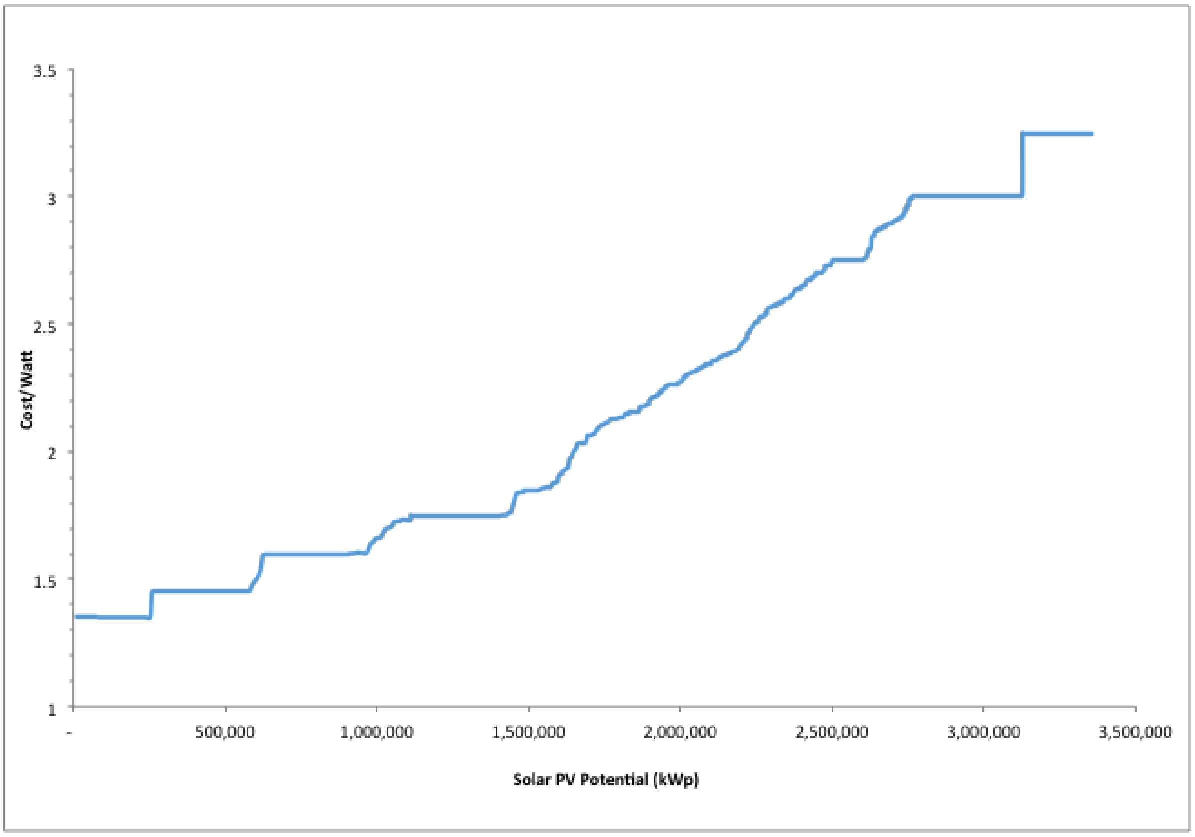
	Ground Mount	Shade Structure	Roof Mounted	Total
PV Capacity (MW[26])	1,891	1,320	144	3,355
PV Production (GWh)	3,025	2,113	230	5,369
Build Cost ($ Millions)	$3,417	$3,977	$371	$7,660
Build Cost ($/Watt)	$1.99	$3.10	$2.62	$2.56
No. of PV Systems	845	886	144	1,875

Generation capacity was determined for the three types of possible solar PV installations: Ground-Mount, Shade Structure/Carport, and Roof Mount. The findings show that the County has a solar PV generation capacity of 3,355 MW and annual solar electricity production potential of 5,369 GWh. Figure 10 shows the aggregate Solar PV supply curve for all County jurisdictions.

Note that the costs shown in Table 2 and Figure 10 are "build costs." Additional soft costs, particularly the acquisition or opportunity cost of the land upon which the ground-mount solar is located, are highly site-specific and not included in these values. These can add up to 50% to the cost of local solar projects, and are accounted for in the CCE scenario modeling.

[26] Local solar PV capacity measured at the panel (i.e., pre-inverter).

Figure 10. Aggregate Solar PV Supply Build Cost Curve, All County



Siting Analysis

To assess the potential locations in Contra Costa County where solar PV could be developed, this study utilized a Geographic Information System (GIS)-based desktop review, incorporating aerial imagery and land-based data. The collected data was analyzed and potential solar PV development sites were identified from criteria established through industry knowledge and input from County stakeholders.

The agreed upon criteria are as follows:

- The minimum acceptable parcel size is three acres. Smaller parcels will not be able to hold an economically viable project. If a potential solar PV system size is below 500 kW it was excluded from the list of potentially feasible sites and overall solar energy capacity.[27] Again, this measure ensures only realistic and economically feasible sites are identified.

- Based on input from the County, only specific tax codes and zoning areas were evaluated. For example, areas such as Open Space or Parks have sufficient land area for solar PV

[27] Residential and other small rooftop solar are accounted for in the California Energy Commission sales forecast used to develop the CCE's demand forecast.

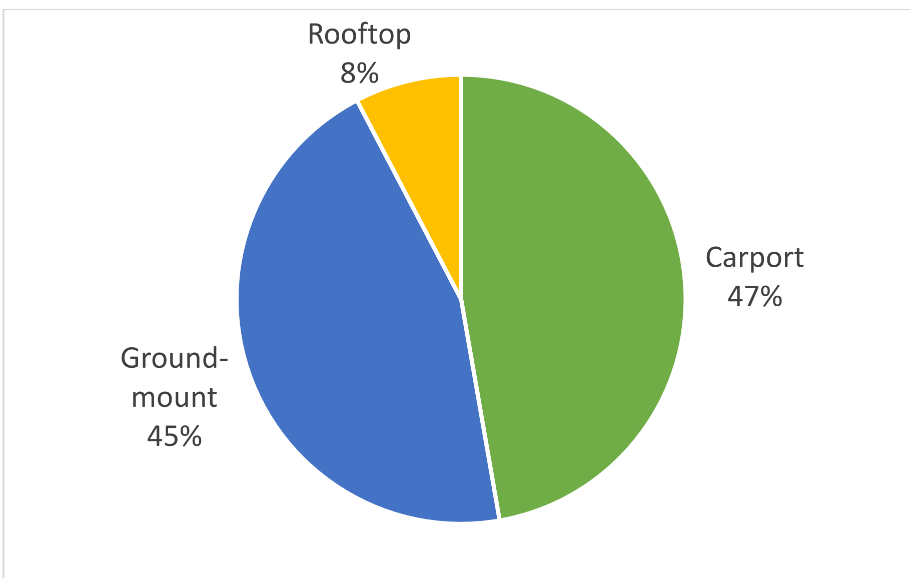
projects, but zoning restrictions would not allow for the development of these projects, and these areas were removed from the approved scope.

- In addition to size and tax/zoning code designations, areas with poor ground quality (marshland), excessive tree density, or excessive sloping would prohibit cost-effective solar PV development and were removed from the analysis.

- Lastly, sites with existing solar were removed from the pool of potential parcels/sites.

Within each identified parcel is the potential for three different types of solar PV development. On impervious land, such as a parking lot, it was assumed that solar PV carports would be installed. On grassland or bare land areas, this analysis assumed a ground-mounted solar PV system would be installed. Lastly, roof-mounted solar PV was assumed for any buildings found in the parcel data that matched the approved criteria. Countywide, 92% of potential installation sites were found to be either carport or ground-mount sites, with only 8% of the sites amenable to roof-mounted PV (Figure 11). The size of the estimated solar PV system was found by analyzing the total land area against the needed land required for solar PV development.

Figure 11. Potential Solar PV Sites by Installation Type



This study found 1,395 parcels that met the established criteria and 1,875 individual sites within the identified parcels where either a solar shade structure, rooftop, or ground-mounted system could be developed. Table 3 shows the individual sites organized by type of solar PV system for each jurisdiction in Contra Costa County.[28]

This assessment also calculated the amount of solar energy production for each of the potential sites identified. The amount of energy production was found by multiplying the estimated system size by an average solar yield. The average solar energy yield was created by designing sample projects that matched the estimated system size in the solar software platform Helioscope. Because Contra Costa County has a variety of solar exposure, multiple sites across the County were designed/tested to find an average yield. Based on our testing, the average yield for Contra Costa County is 1,600 (kWh/kW). The resulting amount of potential PV production per jurisdiction is also provided in Table 3.

[28] For maps, please see https://www.dropbox.com/s/cb3rig66shny68j/Contra%20Costa%20CCE%20Solar%20Siting%20DRAFT%20Report%20SA%202016-11-15%20Reduced%20Size.pdf?dl=0.

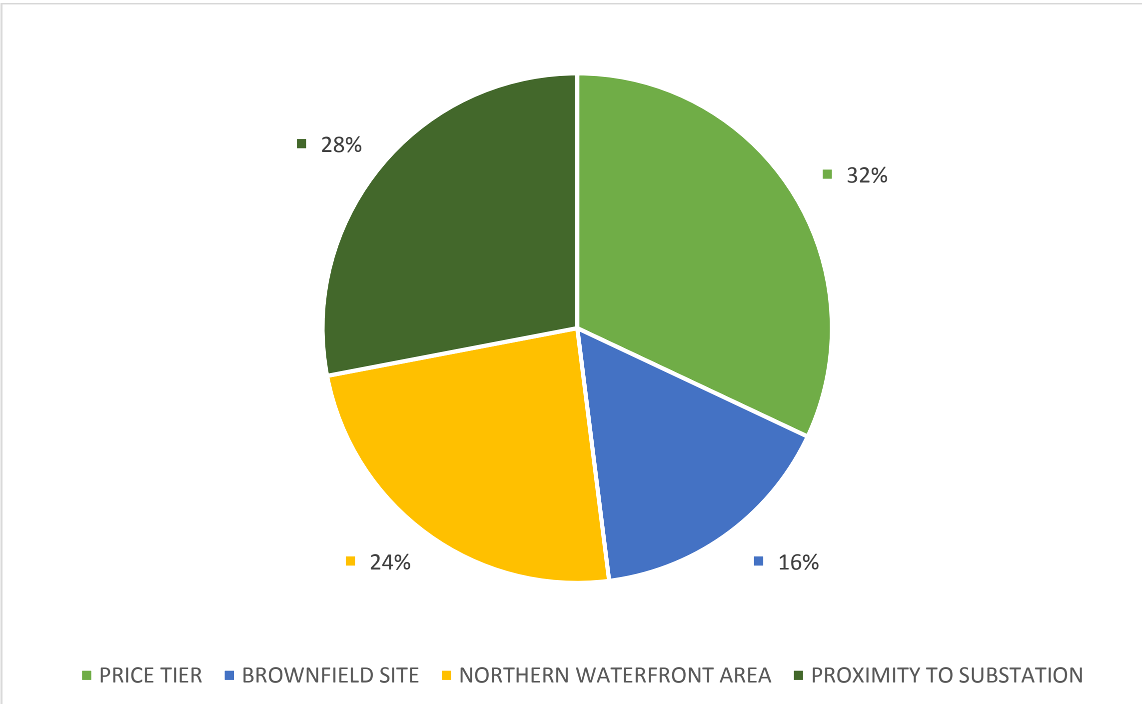
Table 3. Potential PV Production and Build Cost by Location

Jurisdiction	PV Potential (MW)	PV Production (GWh)	Build Cost ($ Millions)
Alamo	14	23	$30,779,000
Antioch	462	739	$1,010,374,000
Brentwood	287	460	$599,685,000
Clayton	38	62	$71,171,000
Concord	370	593	$900,603,000
Crockett	58	93	$125,187,000
Danville	80	129	$177,801,000
El Cerrito	29	48	$73,161,000
El Sobrante	19	31	$42,020,000
Hercules	90	144	$200,511,000
Lafayette	8	13	$23,641,000
Martinez	313	502	$654,701,000
Moraga	24	39	$55,957,000
Oakley	121	194	$285,786,000
Orinda	22	36	$43,554,000
Pinole	47	77	$126,870,000
Pittsburg	314	502	$705,202,000
Pleasant Hill	60	96	$164,364,000
Port Costa	8	13	$13,501,000
Richmond	502	804	$1,261,541,000
Rodeo	35	57	$85,874,000
San Pablo	191	307	$459,784,000
San Ramon	158	254	$384,634,000
Walnut Creek	95	152	$269,795,000
Grand Total	**3,355**	**5,369**	**$7,766,496,000**

Ranking

After the feasible solar sites and the corresponding solar PV capacity were identified, each site was ranked. The ranking was weighted based on how important it was to the actual feasibility of developing the site for solar PV and based on input from County stakeholders. The ranking consisted of the following measures as shown in the figure below.

Figure 12. Weighted Ranking Categories



An overall ranking score was then applied to each individual site to illustrate the best and worst sites for solar PV development. Sites were then grouped in tiers one through five, with one being the best. In addition to the ranking score, industry knowledge indicates the best sites to develop a feasible solar PV project will be larger than 1 MW, located on government land, and will be a ground-mounted solar array, the most cost-effective installation type. The table below shows the key characteristics of the ranking analysis.

Table 4. Ranking Values for All Sites

Ranking Tier	Sum of PV Production (GWh)	Sum of Total Price	Average Build Price per Watt
1	1,309	$1,591,810,000	$2.13
2	1,167	$1,578,770,000	$2.37
3	1,105	$1,622,236,000	$2.57
4	868	$1,251,547,000	$2.56
5	919	$1,722,142,000	$3.07

Local Solar Modeled in the CCE Scenarios

To estimate the contribution of local solar to a Contra Costa CCE's supply costs, we used the supply curve shown in Figure 10. To translate the $/kW costs in the figure to $/MWh generation costs, we used the pro forma model contained in the CPUC's RPS Calculator and the cost and performance assumptions provided by Sage for the County. For example, the lowest-cost projects at $1,350/kW were estimated to have a generation cost of $98/MWh ($68/MWh for build costs and $30/MWh for soft and land acquisition/opportunity costs).

The generation cost was assumed to scale with installed cost. Because it is unlikely that all the identified sites would be developed in order of their increasing cost (and some sites may never be developed regardless of economics), we assumed that 50% of the capacity identified in the cost curve would be developed for the purpose of conservatively estimating average costs at each level of local solar penetration. We calculated the average price for the cumulative developed capacity forecast for each year (again, counting only 50% of the capacity of each developed project towards the cumulative total). For Scenarios 3 and 4, we assumed that 50% of the CCA's RPS supply would be provided by local solar by 2027, adding 620 MW of local solar under Scenario 3 and 990 MW under Scenario 4 by 2030. (Scenarios 1 and 2 do not include any local solar.)

Greenhouse Gas Costs

MRW estimated that the price of GHG allowances would equal the auction floor price stipulated by the California Air Resources Board’s cap-and-trade regulations, consistent with recent auction outcomes.[29]

Table 5. GHG Allowances price[30]

	2017	2018	2019	2025	2030	2035	2038
$/tonne	13.2	14.7	15.9	24.4	34.7	49.8	61.8

Total GHG costs were calculated by multiplying the allowance price by the amount of carbon emitted per megawatt-hour for each assumed resource. For “system” purchases, MRW assumed that the GHG emissions corresponded to a natural gas generator operating at the market heat rate. This worked out to be, on average over 2018-2038, approximately $1.5/MWh delivered.[31]

Other CCE Supply Costs

The CCE is expected to incur additional costs associated with its procurement function. For example, if the CCE relies on a third-party energy marketing company to manage its portfolio it will likely incur broker fees or other expenses equal to roughly 5% of the forecasted contract costs. The CCE would also incur costs charged by the California Independent System Operator

[29] California Code of Regulations, Title 17, Article 5, Section 95911. Auction results available at http://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf.
[30] For 2017, the amount listed corresponds to the GHG allowance price for PG&E according to the most recent ERRA 2017 update. Pacific Gas & Electric ERRA 2017, A.16-06-003, Testimony November 2, 2016, Table 12-1.
[31] The amount of GHG emissions will depend on the generation portfolio. $1.50/MWh corresponds to the GHG emissions costs under Scenario 1.

(CAISO) for ancillary services (activities required to ensure reliability) and other expenses. MRW added 5.5% to the CCE's power supply cost to cover these CAISO costs. Finally, we added an expense associated with managing the CCE's renewable supply portfolio. Based on an analysis of the expected CCE load shape and the typical generation profile of California solar and wind resources, we observed that there will be hours in which the expected deliveries from renewable contracts will be greater than the CCE's load in that hour. This results from the amount of renewable capacity that must be contracted to meet annual RPS targets and the variability in renewable generation that leads to higher deliveries in some hours and lower deliveries in other hours. When high renewable energy deliveries coincide with low loads, the CCE will need to sell the excess energy, likely at a loss, or curtail deliveries, and will potentially have to make up those renewable energy purchases during higher load hours to comply with the RPS. The result is that the procurement costs will be somewhat higher than simply contracting with sufficient capacity to meet the annual RPS.

PG&E Rate and Exit Fee Forecasts

MRW developed a forecast of PG&E's bundled generation rates and CCE exit fees in order to compare the projected rates that customers would pay as Contra Costa County CCE customers to the projected rates and fees they would pay as bundled PG&E customers.

PG&E Bundled Generation Rates

To ensure a consistent and reliable financial analysis, MRW developed a 20-year forecast of PG&E's bundled generation rates using market prices for renewable energy purchases, market power purchases, greenhouse gas allowances, and capacity that are consistent with those used in the forecast of Contra Costa County CCE's supply costs. MRW additionally forecast the cost of PG&E's existing resource portfolio, adding in market purchases only when necessary to meet projected demand. MRW assumed that near-term changes to PG&E's generation portfolio would be driven primarily by increases to the Renewable Portfolio Standard requirement in the years leading up to 2030 and by the retirement of the Diablo Canyon nuclear units at the end of their current license periods in 2024 and 2025. More information about this forecast is provided in Appendix B.

MRW forecasts that, on average, PG&E's generation rates will increase faster than inflation through 2038, with 2038 rates more than 20% higher than today's rates when considered on a constant dollar basis (i.e., assuming zero inflation). Underlying this result are three distinct rate periods:

1. An initial period of faster rate growth from 2018 to 2022 (1% annually above inflation);
2. A period of rate decline from 2023 to 2025 (3.5% annually below inflation), primarily due to the retirement of Diablo Canyon[32]; and
3. A period of steeper rate growth between 2026 and 2030 (3.5% annually above inflation), primarily due to the replacement of Diablo Canyon with more expensive resources: energy efficiency, renewable generation, and fuel-fired generation. In addition, the retirement of Diablo Canyon increases the demand in capacity with a consequent increase

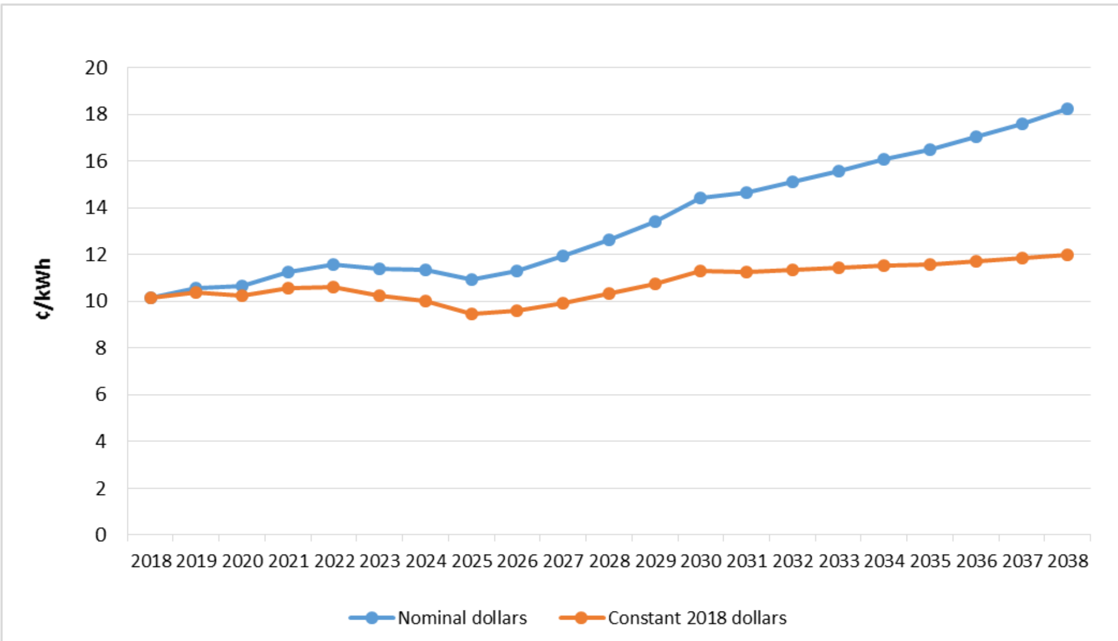
[32] More information can be found in Appendix C

in capacity prices.

4. A final period of moderate rate growth through 2038 (1% annually above inflation), primarily due to the replacement of high-cost renewable power contracts currently in PG&E's portfolio with new lower-priced contracts (reflecting the significant fall in renewable power prices in recent years).

PG&E's bundled generation rates in each year of MRW's forecast are shown in Figure 13, on both a nominal and constant-dollar basis.

Figure 13: PG&E Bundled Generation Rates, nominal and constant-dollar forecasts



PG&E Exit Fee Forecast

In addition to the bundled rate forecast, MRW developed a forecast of the Power Charge Indifference Adjustment ("PCIA"), which is a PG&E exit fee that is charged to CCE customers. The PCIA is intended to pay for the above-market costs of PG&E generation resources that were acquired, or which PG&E committed to acquire, prior to the customer's departure to CCE. The total cost of these resources is compared to a market-based price benchmark to calculate the "stranded costs" associated with these resources, and CCE customers are charged what is determined to be their fair share of the stranded costs through the PCIA.

MRW forecasted the PCIA charge by modeling expected changes to PCIA-eligible resources and to the market-based price benchmark through 2038, using assumptions consistent with those used in the PG&E rate model. Based on our modelling, we expect the PCIA to decline in most years until it drops off completely around 2034. MRW's forecast of the residential PCIA charge through 2038 is summarized in Table 6.

Table 6. PG&E Residential PCIA Charges

	2018	2019	2020	2025	2030	2035	2038
¢/kWh	2.4	1.9	2.3	1.3	0.5	0.0	0.0

In its Diablo Canyon retirement application, PG&E proposed an additional exit fee, dubbed the "Clean Energy Charge" (CEC) which CCE customers would pay to offset some of the incremental costs PG&E would incur for developing its greener portfolio. This proposal was later withdrawn. Furthermore, no party participating in the proceeding supported this charge. Because of the lack of support for the "CEC," and the fact that PG&E's application would have allowed CCEs to get out of the charge by procuring renewable power above and beyond the RPS requirement, we do not quantify or include this hypothetical charge in the analysis.

Pro Forma Elements and CCE Costs of Service

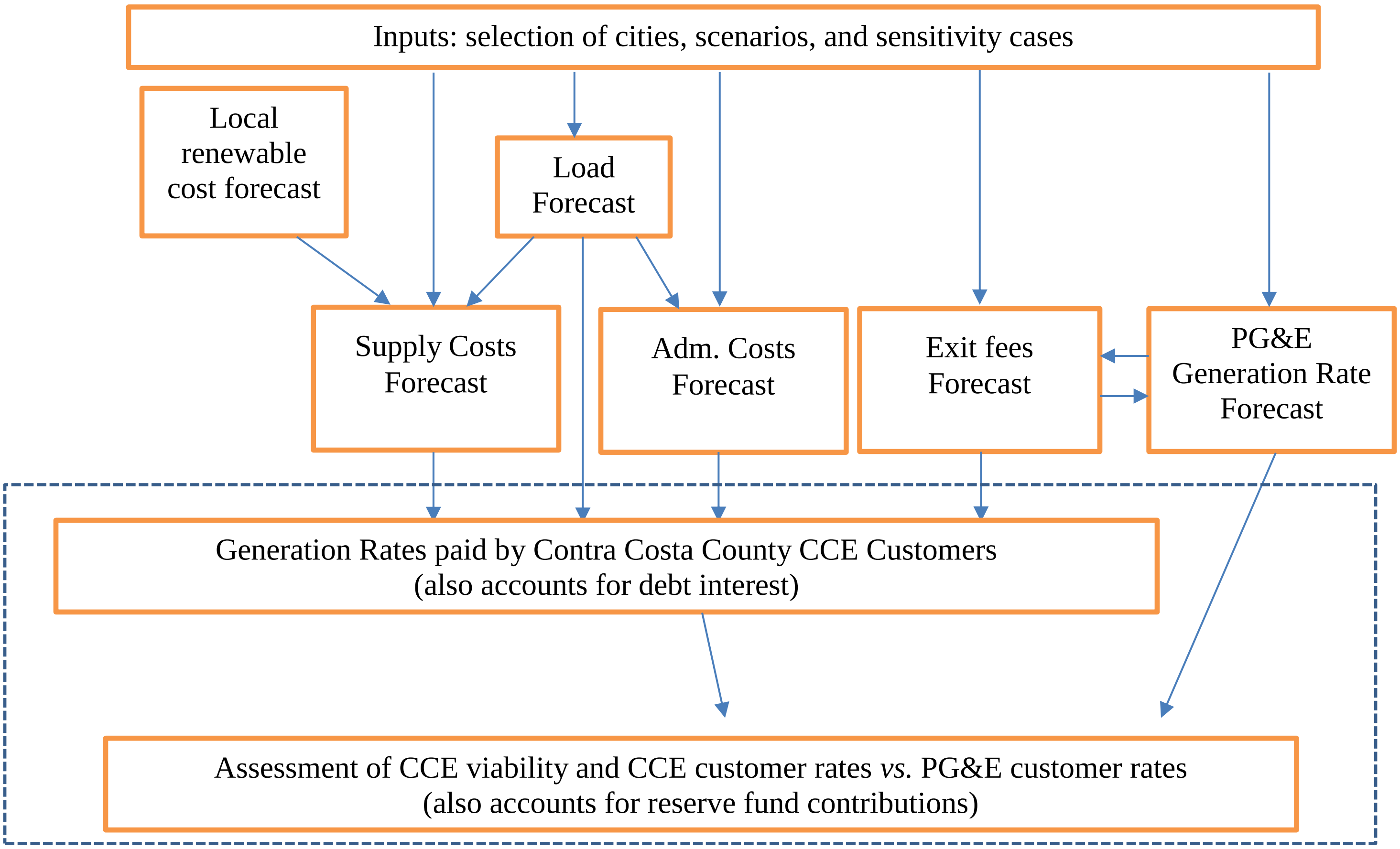
MRW conducted a pro forma analysis to evaluate the expected financial performance of the CCE and the CCE's competitive position *vis a vis* PG&E. The analysis was conducted on a forward-looking basis from the expected start of CCE operations in 2018 through the year 2038, with several cases considered to address uncertainty in future circumstances.

Pro Forma Elements

Figure 14 provides a schematic of the pro forma analysis, outlining the input elements of the analysis and the output results. The analysis involves a comparison between the generation-related costs that would be paid by Contra Costa County CCE customers and the generation-related costs that would be paid by PG&E bundled service customers. Costs paid by CCE customers include all CCE-related costs (i.e., supply portfolio costs and administrative and general costs) and exit fee payments that CCE customers will be required to make to PG&E.

As discussed in previous sections, supply portfolio costs are informed and affected by CCE loads, by the requirements the CCE will need to meet (or will choose to meet) such as with respect to renewable procurement, and by CCE participation levels, which can vary depending on whether or not all cities in the County choose to join the CCE. Administrative and general costs are discussed further below.

Figure 14. Pro forma Analysis



Startup Costs

Table 7 shows the estimated CCE startup costs. They are based on the experience of existing CCEs as well as other CCE technical and feasibility assessments. Working capital is set to equal one hundred days of CCE revenue[33], or approximately $22 million. This amount would cover the timing lag between when invoices for power purchases (and other account payables) must be remitted and when income is received from the customers. Initially, the working capital is provided to the CCE on credit from a bank. Typical power purchase contracts require payment for the prior month's purchases by the 20th of the current month. Customers' payments are typically received 60 to 90 days from when the power is delivered.

These startup costs are assumed to be financed over 5 years at 5% interest.

[33] The working capital has been calculated in base to Scenario 1.

Table 7. Estimated Start-Up Costs

Item	Cost
Technical Study	$200,000
JPA Formation/Development	$100,000
Implementation Plan Development	$50,000
Power Supplier Solicitation & Contracting	$75,000
Staffing	$700,000
Consultants and Legal Counsel	$400,000
Marketing & Communications	$250,000
PG&E Service Fees	$75,000
CCA Bond	$100,000
Miscellaneous	$300,000
Total	**$2,250,000**
Working Capital	$21,500,000
Total	**$23,750,000**

Administrative and General Cost Inputs

Administrative and general costs cover the everyday operations of the CCE, including costs for billing, data management, customer service, employee salaries, contractor payments, and fees paid to PG&E. MRW conducted a survey of the financial reports of existing CCEs to develop estimates of the costs that would be faced by a Contra Costa County CCE. Administrative and general costs are phased in from 2018 to 2020, as the CCE operations expand to cover the entire territory of the County; after that, costs are escalated by 2% each year to account for the effects of inflation.

Administrative and general costs are unchanged under the three renewable level scenarios, but do vary based on how many cities join the CCE and the number of participating customer accounts. As previously mentioned, a 15% opt-out rate has been assumed for customer participation.

Cost of Service Analysis and Reserve Fund

To determine annual CCE costs and the rates that would need to be charged to CCE customers to cover these costs, MRW summed the two categories of CCE costs (i.e., supply portfolio costs, and administrative and general costs) and added in debt financing to cover start-up costs and initial working capital. Financing was assumed to be for a five-year period at an interest rate of 5%. These costs were divided by projected CCE loads to develop the average rate the CCE would need to charge customers to cover its costs ("minimum CCE rate").

To establish the Contra Costa County CCE rate, MRW adjusted the minimum CCE rate, if needed, based on the competitive position of the CCE. In particular, when the total CCE customer rate (i.e., the minimum CCE rate plus the PG&E exit fee) was below the projected PG&E generation rate,[34] MRW increased the minimum CCE rate up to the amount needed to meet the reserve refund targets while still maintaining a discount. MRW used the surplus CCE revenue from these rate increases ("Reserve Fund") in order to maintain Contra Costa County CCE competitiveness with PG&E rates in years in which total CCE customer rates would otherwise be higher than PG&E generation rates.[35]

[34] For this analysis, MRW used the average of the projected PG&E generation rates across all rate classes, weighted by the projected Contra Costa County CCE load in each rate class.
[35] MRW applied a Reserve Fund cap of 15% of the annual operating cost. After this cap was reached, no further rate increases were applied for the purpose of Reserve Fund contributions.

Chapter 3: Cost and Benefit Analysis

As described in the prior chapter, as part of the pro forma analysis, MRW calculated Contra Costa County CCE rates that would, where feasible, cover CCE costs and maintain long-term competitiveness with PG&E. This chapter uses those rates to compare the costs and benefits of the Contra Costa County CCE across four scenarios: (1) Minimum RPS Compliance, (2) Accelerated RPS, (3) Minimum RPS Compliance plus Local Procurement, and (4) Accelerated RPS plus Local Procurement. Costs and benefits are evaluated by comparing total CCE customer rates (including PG&E exit fees) to PG&E generation.

Scenario 1 (Minimum RPS Compliance)

Under Scenario 1, the Contra Costa County CCE meets all RPS requirements (including California State Senate Bill 350 and Diablo Canyon retirement proposal requirements), and 35% of the total load over the 20-year period is met through large hydroelectricity.[36]

CCE Average Costs

Figure 15 summarizes the results of this scenario. The vertical bars represent the total Contra Costa County CCE customer rate and the green line represents a comparable PG&E generation rate.[37] Non-renewable generation (including large hydroelectric) is responsible for the bulk of the CCE's costs. Renewable generation costs will continue to increase throughout the forecast period due to the increasing RPS standards. Regarding customer costs, the PCIA exit fee is expected to decrease after 2020. Finally, the GHG allowance purchases represent a small portion of the total costs because 60% of the non-renewable generation is met by hydroelectricity. This non-carbon emitting resource therefore limits the need to purchase GHG allowances.

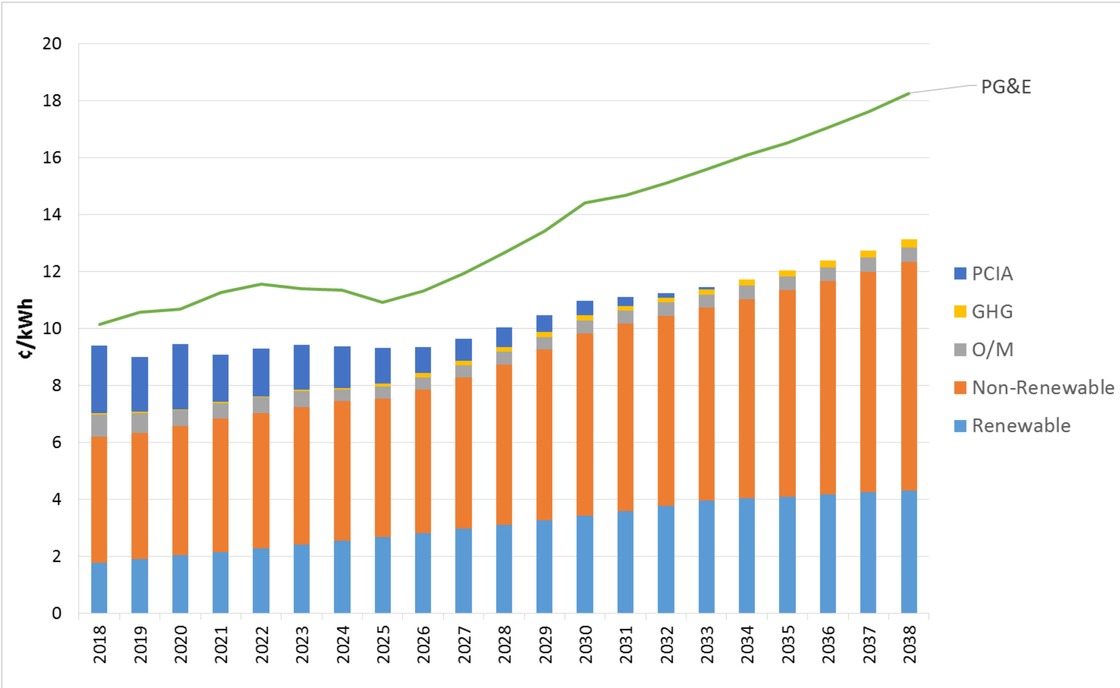
Note that this figure and the analogous ones to follow do not account for contributions to a rate reserve fund or other potential CCE activities such as energy efficiency or other community programs.

Under Scenario 1, the differential between PG&E generation rates and Contra Costa County CCE customer rates is positive in each year (i.e., CCE rates are lower than PG&E rates). As a result, Contra Costa County CCE customers' average generation rates (including contributions to the reserve fund) can be set at a level that is lower than PG&E's average customer generation rate in each year. The annual differential between the PG&E rate and the total CCE customer rate is expected to vary significantly over the course of this period (Figure 15). During the initial period from 2018-2022, the differential between the two rates increases (i.e., the CCE becomes more cost-competitive) as PG&E's rates rise, and the exit fees charged to Contra Costa County CCE customers fall as PG&E-owned gas plants expire from PCIA eligibility. Beginning in 2024, the rate differential narrows due to a decrease in PG&E generation rates stemming from the closure of the Diablo Canyon nuclear plant. After 2026, the difference between the two rates is

[36] 60% of the non-RPS generation in average for 2018-2038.
[37] All rates are in nominal dollars.

expected to increase as PG&E's generation rates continue to increase and exit fees decline with the expiration of additional resources from PCIA eligibility.

Figure 15. Scenario 1 Forecast Average CCE Cost and PG&E Rates, 2018-2038[38]



Residential Bill Impacts

Table 8 shows the average annual savings for residential customers under Scenario 1. The average annual bill for the residential customer on the Contra Costa County CCE program will be on average 8% lower than the same bill on PG&E rates. Note that these rate impacts assume that a rate stabilization reserve is funded during the first few years of the CCE's existence.

Table 8. Scenario 1 Savings for Residential CCE Customers

Residential	Monthly Consumption (kWh)	Bill with PG&E ($)	Bill with Contra Costa County CCA ($)	Savings ($)	Savings (%)
2018	500	121	121	0	0%
2020	500	129	124	5	4%
2030	500	189	171	18	10%
2038	500	254	227	27	11%

[38] This chart does not include the reserve fund.

Greenhouse Gas Emissions

Under Scenario 1, we model the Contra Costa County CCE to be 50% below PG&E's GHG emission rate. It can meet this goal by using large hydroelectric power to meet 35% of its resource needs (60% of the non-RPS load). Though this large hydro power would not qualify for RPS requirements, it is nevertheless a non-carbon emitting resource.

Figure 16 shows the Contra Costa CCE's generation portfolio mix (vertical bars) and GHG emissions rate (brown line) under Scenario 1, along with PG&E's GHG emissions rate for comparison (blue line). Additional GHG savings can occur if additional renewables are added to the portfolio (see Scenarios 2 and 4) or if a greater fraction of GHG-free resources (like large hydro) is used.

PG&E GHG emissions are relatively low due to the diversity in PG&E's electric mix. In addition to renewable generation, over 40% of PG&E's supply portfolio is made up of nuclear and large hydroelectric generation, both of which are considered GHG-free generation technologies. PG&E's GHG emissions rate is expected to fall between 2018 and 2020 due to increases in RPS procurement. In 2025, the retirement of the Diablo Canyon nuclear generation plant is expected to more than double PG&E's GHG emission rate as the utility increases its gas-fired generation to make up for a share of the loss.[39] In the following years PG&E's GHG emissions are expected to decrease as PG&E ramps up renewable procurement to meet its mandated RPS goals and the additional RPS procurement required under the Diablo Canyon retirement proposal.[40] In this scenario, the CCE's emissions rate is set to be approximately 50% of PG&E's in each year, subject to a 5% minimum supply from market purchases.

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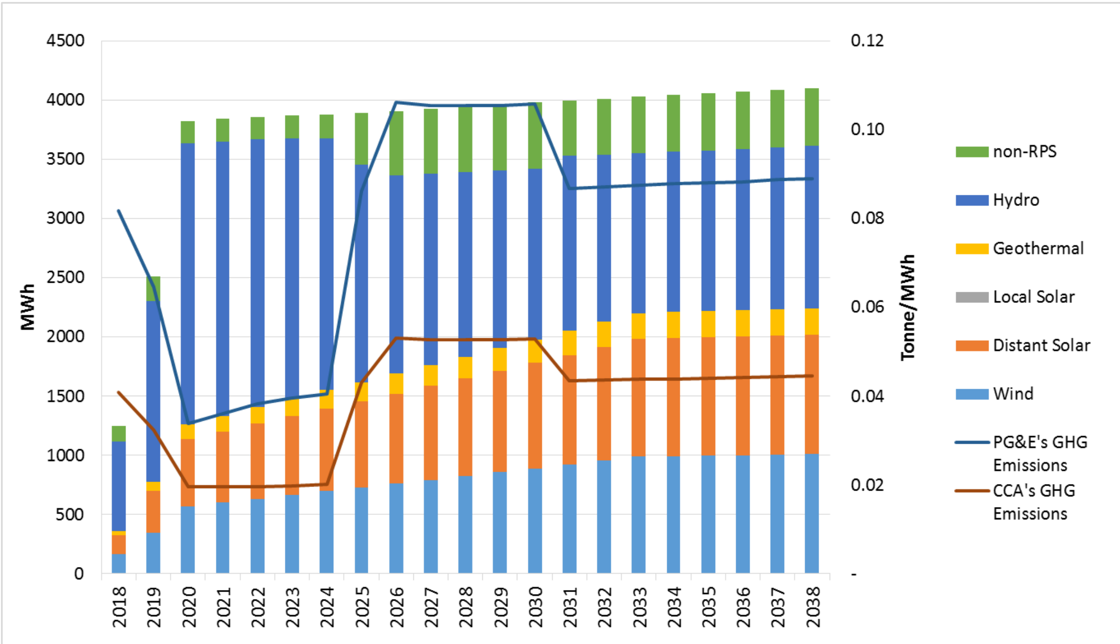
[39] Even if PG&E replaces the nuclear generation with renewable power and other GHG-free resources, as proposed, the new renewable resources will need to be balanced by flexible resources, which are likely to be at least in part provided by fossil-fueled power and which will therefore increase PG&E's GHG emissions.
[40] Starting in 2030, the required RPS increases from 50% to 55% under PG&E's proposal.

Figure 16. Scenario 1 Contra Costa County CCE Supply Portfolio (vertical bars) and GHG Emissions (lines) ("Normal" PG&E Hydro Conditions)



Scenario 2 (Accelerated RPS)

Scenario 2, from a renewable procurement perspective, is a more aggressive scenario. Under this scenario, the Contra Costa County CCE starts with 50% of its load served by renewable sources in 2018, and rapidly increases to 80% of its load served by renewable sources in 2030. In addition, between 2018 and 2038 Contra Costa County will provide an average of 20% of its supply though large hydroelectric sources[41].

CCE Average Costs

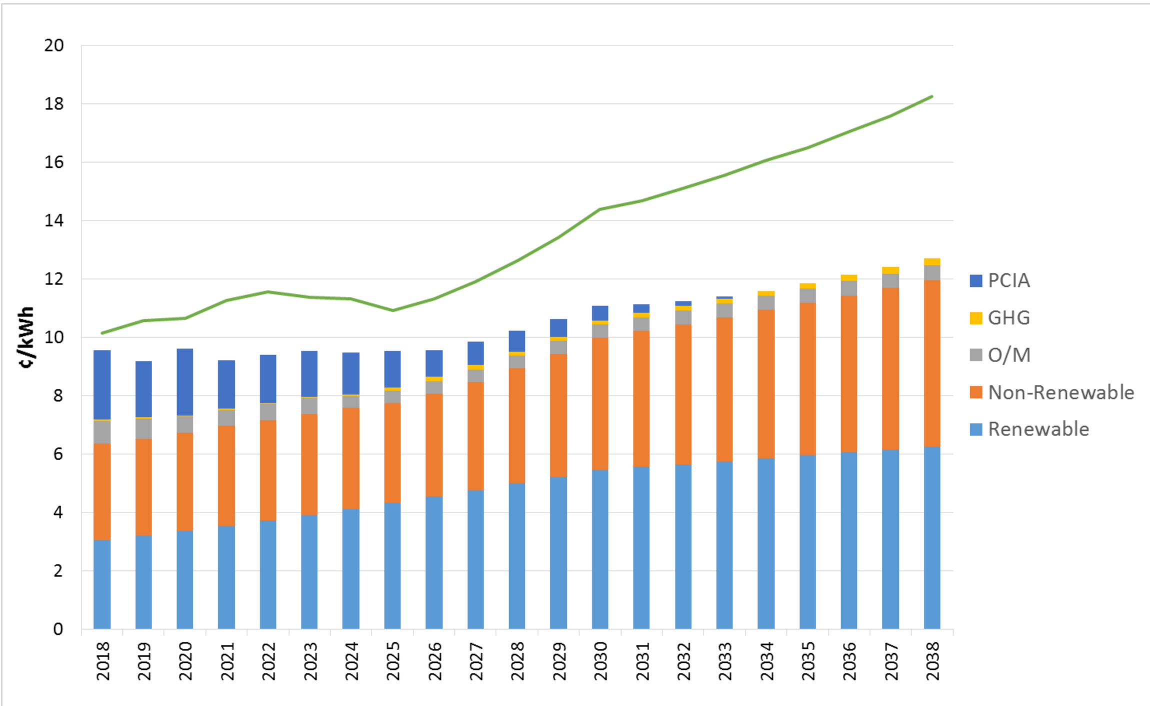
Figure 17 summarizes the results for this scenario. The vertical bars represent the Contra Costa County CCE customer rate, and the green line represents the PG&E generation rate. In this scenario, the renewable power cost is the single largest element of the CCE rate, reflecting the higher renewable content of this scenario. Non-renewable generation and the PCIA exit fee are the second and third most expensive components, respectively. As in Scenario 1, the PCIA exit fee is expected to decrease in most years beginning in 2020. Because of this scenario's larger share of GHG-free generation between 2028 and 2038, the GHG allowance purchases are an even lower portion of the total costs.

Compared to Scenario 1, Scenario 2 exhibits a lower differential between PG&E's and the CCE's customer generation rates between 2018 and 2033. After 2033, the price of renewable generation is expected to undercut the wholesale electricity market for non-RPS supplies, rendering a higher

[41] 50% of the non-RPS generation for 2018-2028.

differential in Scenario 2 than in Scenario 1. With respect to PG&E's rates, this differential will continue to follow a similar pattern: positive for all years from 2018 to 2038. And as was the case in Scenario 1, Scenario 2 enables the CCE to reliably price its average generation rates lower than those of PG&E.

Figure 17. Scenario 2 Forecast Average CCE Cost and PG&E Rates, 2018-2038[42]



Residential Bill Impacts

Table 9 summarizes the average annual savings for residential customers under Scenario 2. For the 2018-2038 period, the average annual bill for a residential customer of the Contra Costa County CCE program will be 8% lower than the same bill under PG&E rates. This is a little less than, but close to, the bill savings under Scenario 1. Note that these rate impacts assume that a rate stabilization reserve is funded during the first few years of the CCE's existence. Thus, even though a "gap" between the CCE costs and PG&E rates can be seen in Figure 17, the bill savings in 2018 is zero, as the additional CCE funds are assume to go to the reserve rather than as a customer bill savings.

[42] This chart does not include the reserve fund.

Table 9. Scenario 2 Savings for Residential CCE Customers

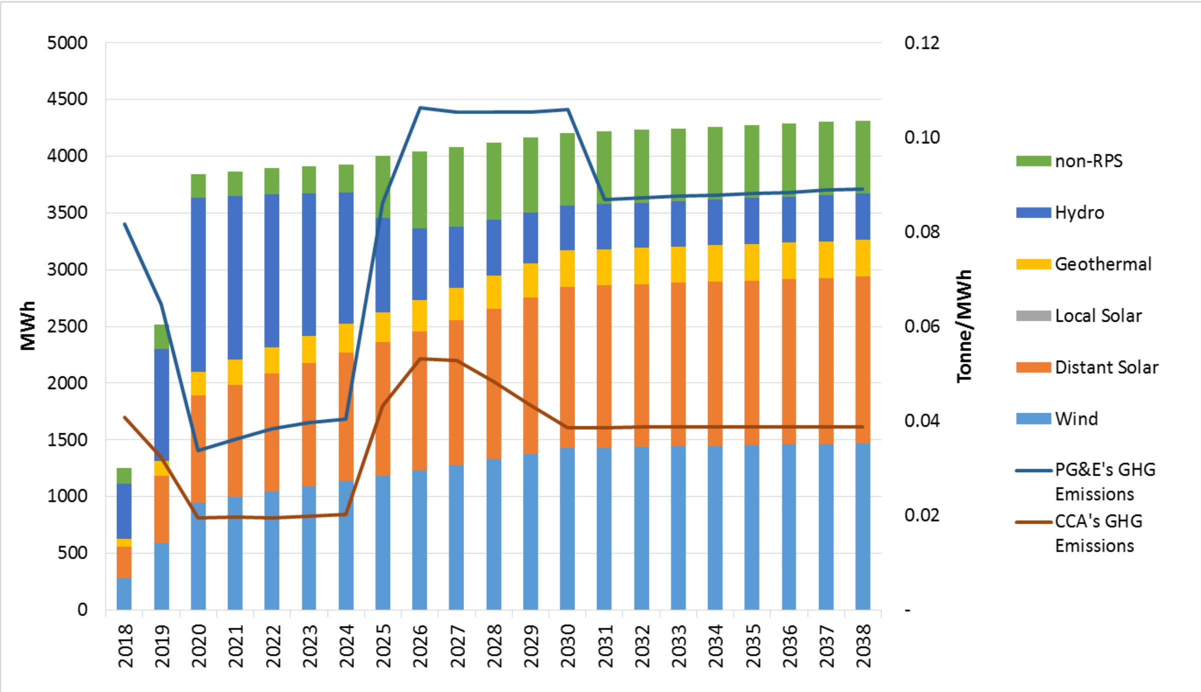
Residential	Monthly Consumption (kWh)	Bill with PG&E ($)	Bill with Contra Costa County CCE ($)	Savings ($)	Savings (%)
2018	500	121	121	0	0%
2020	500	129	125	4	3%
2030	500	189	172	17	9%
2038	500	254	225	29	11%

GHG Emissions

Under Scenario 2, we model the Contra Costa County CCE to at least as much carbon-free generation as PG&E. As in Scenario 1, in years where the assumed renewables would not result in the CCE halving PG&E's GHG emissions, we add large hydroelectric generation to the CCE's resource portfolio to make up the difference, subject to a 5% minimum supply from market purchases. In other years when the CCE's RPS targets are sufficient to provide GHG savings relative to PG&E, we assume that emissions are further reduced by sourcing 50% of the non-RPS supply from large hydro. The result is a portfolio that averages 20% large hydro.

Figure 18 compares the Scenario 2 GHG emissions from 2018-2038 for the Contra Costa County CCE with what PG&E's emissions would be for the same load if no CCE were formed. Because Scenario 2 has a higher renewable generation target (80% by 2030), the hydroelectric generation necessary to achieve the same GHG emissions reduction is lower. As a result of trading off large hydro for RPS-eligible energy, GHG emissions in Scenario 2 are the same as Scenario 1 through 2027, after which the CCE's portfolio will produce less than half the GHG emissions compared to PG&E.

Figure 18. Scenario 2 Contra Costa County CCE Supply Portfolio (vertical bars) and GHG Emissions (lines) ("Normal" PG&E Hydro Conditions)



Scenario 3 (Minimum RPS Compliance plus Local Procurement)

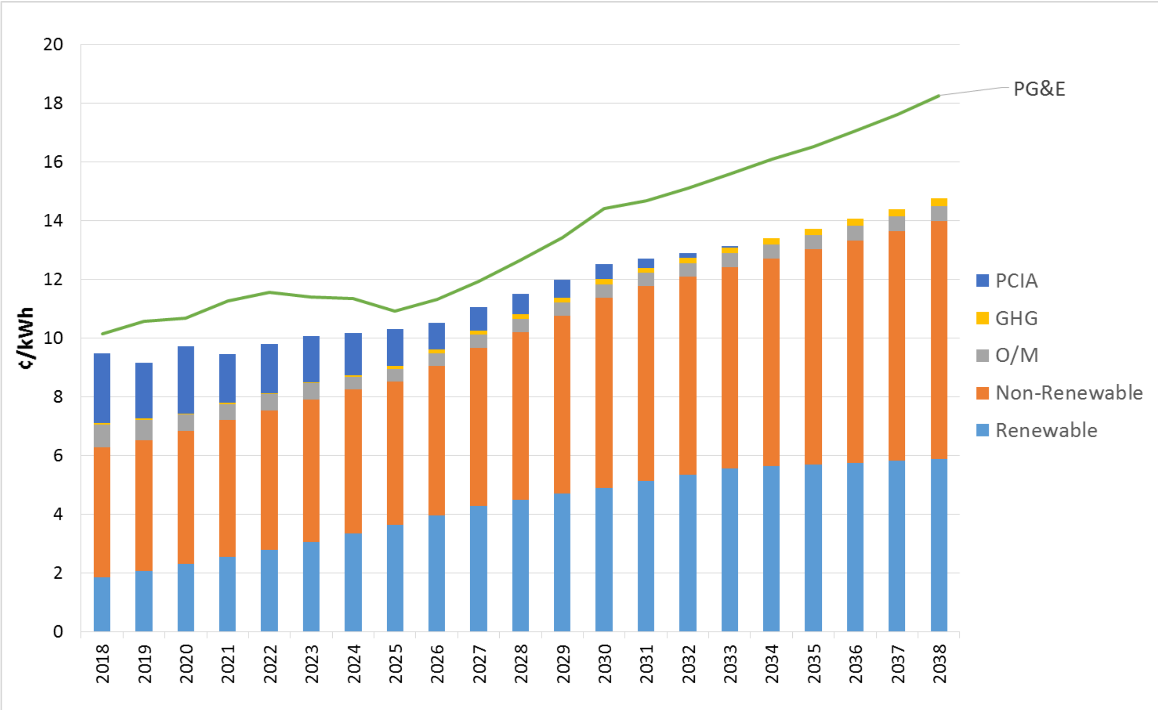
Scenario 3 is identical to Scenario 1, save for a greater portion of locally sourced renewables. Under Scenario 3, local renewables increase annually, reaching 50% of the renewable supply by 2027 and continues at 50% through 2038.

CCE Costs

Figure 19 summarizes the results for this scenario. The vertical bars represent the Contra Costa County CCE customer rate, and the green line represents the PG&E generation rate. As with Scenario 1, the non-renewable cost is the largest component of the CCE's rates, followed by renewable generation costs. The latter are greater than in Scenario 1 due to the higher prices of local generation resources. As with previous scenarios, the PCIA exit fee is the third largest expenditure and it is expected to decrease most years after 2020. As with Scenario 1, the costs associated with GHG allowance purchases are responsible for a marginally larger percentage of the CCE's total costs between 2028 and 2038. This is mostly due to the lower share of GHG-free emissions.

The Scenario 3 differential between PG&E generation rates and Contra Costa County CCE rates falls below the differential in Scenarios 1 and 2. However, the CCE rates are expected to be lower than PG&E's generation rates for the entire forecast period, which will allow the CCE to collect reserve fund contributions annually from 2018 to 2038.

Figure 19. Scenario 3: Forecast Average CCE Cost and PG&E Rates, 2018-2038



Residential Bill Impacts

Table 10 summarizes the average residential bill impacts under Scenario 3. Between 2018 and 2038, the annual bill for a residential customer of the Contra Costa County CCE program will be, on average, 4.5% lower than a corresponding PG&E bill.

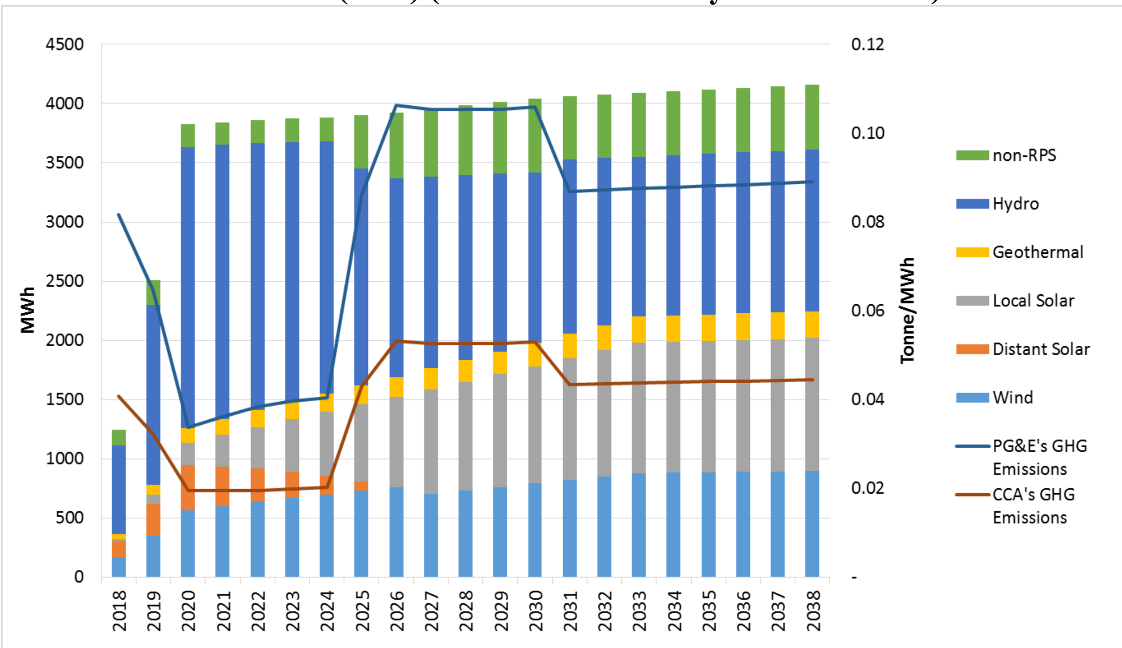
Table 10. Scenario 3 Savings for Residential CCE Customers

Residential	Monthly Consumption (kWh)	Bill with PG&E ($)	Bill with Contra Costa County CCA ($)	Savings ($)	Savings (%)
2018	500	121	121	0	0%
2020	500	129	126	3	2%
2030	500	189	179	10	5%
2038	500	254	236	18	7%

GHG Emissions

The emissions pattern for Scenario 3 is identical to Scenario 1 due to the equal GHG-free generation proportion. The only difference is that part of this generation is provided by local sources. Figure 20 shows the GHG emissions from 2018-2038 for the Contra Costa County CCE under Scenario 3. Note that GHG emissions from the Contra Costa CCE supply and PG&E supply are the same as in Scenario 1.

Figure 20. Scenario 3 Contra Costa County CCE Supply Portfolio (vertical bars) and GHG Emissions (lines) ("Normal" PG&E Hydro Conditions)



Scenario 4 (Accelerated RPS plus Local Procurement)

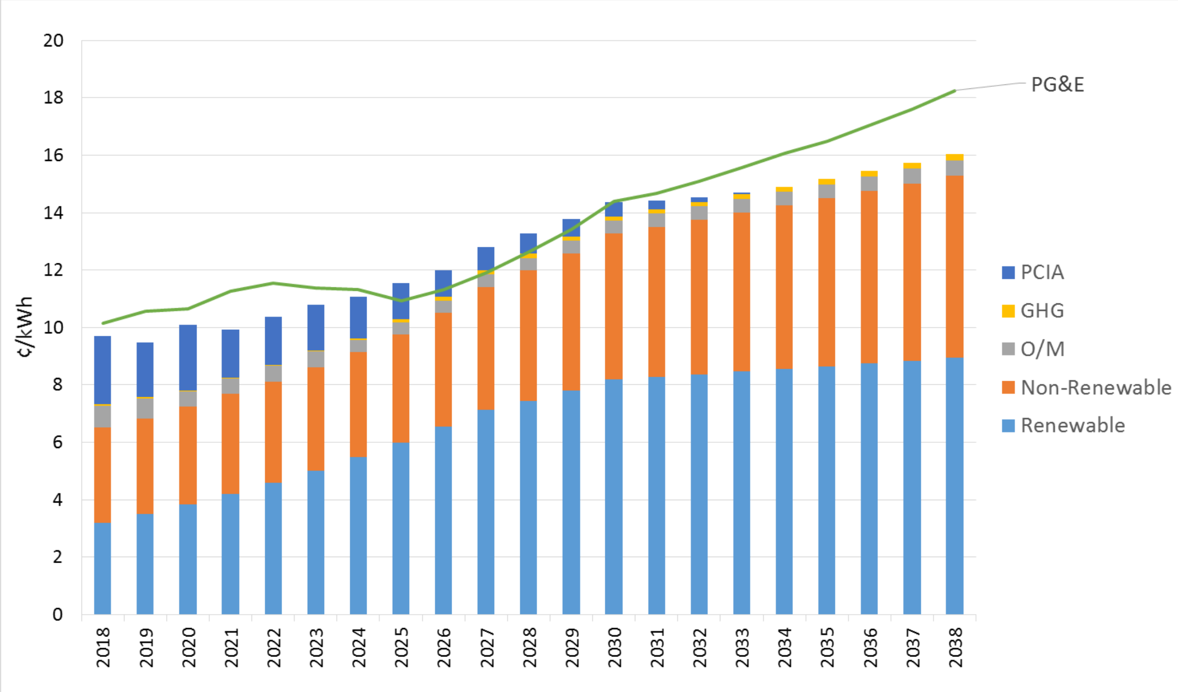
Scenario 4 is the same scenario as Scenario 2 but with a more substantial portion of the generation sourced from local renewable sources: increasing annually and achieving 50% of the total RPS supply by 2027 through 2038.

CCE Average Costs

Figure 21 summarizes the results for this scenario. The vertical bars represent the Contra Costa County CCE customer rate, and the green line represents the PG&E generation rate. Under Scenario 4, the cost for renewables forms the largest component of the CCE's rates and grows steadily to account for nearly 60% of the total CCE rate in 2030. Non-renewable generation is the next largest cost component of the rate, followed by the PCIA exit fee, which is expected to decrease in most years beginning 2020. As with Scenario 2, the costs for GHG allowance purchases in Scenario 4 are a smaller portion of total costs because of more RPS power.

The differential between PG&E generation rates and Contra Costa County CCE customer rates from 2018 to 2038 in Scenario 4 is the lowest of the four scenarios. This is because Scenario 4 has the most expensive supply portfolio, comprised of more locally sources renewables. Similar to the other scenarios, in Scenario 4 the collection of the reserve fund contributions at the end of 2038 is positive. Contra Costa County CCE rates in Scenario 4 are forecasted to be lower than expected PG&E generation rates for all years from 2018 to 2038, except from 2025 to 2030.

Figure 21. Scenario 4: Forecast Average CCE Cost and PG&E Rates, 2017-2038



Residential Bill Impacts

Table 11 summarizes the average residential bill impacts under Scenario 4. Over the study period, the annual bill for a residential customer of the Contra Costa County CCE program will be, on average, 1% lower than the same bill under PG&E rates under Scenario 4. However, the higher local renewable costs coupled with their assumed high usage cause the CCE's rates to exceed PG&E's in some years. In particular, from 2025 through 2030, the total CCE rates (CCE rate plus PCIA) is projected to be higher than the PG&E generation rate. This implies that very aggressive pursuit of local renewables must be carefully weighed against their additional costs.

However, it should also be noted that the study assumed a conservative $30/MWh adder on top of the build costs of local solar projects to account for costs of land acquisition/ opportunity costs. If a significant fraction of the local projects does not have these higher soft costs, then this higher level of local renewables can be developed at competitive rates.

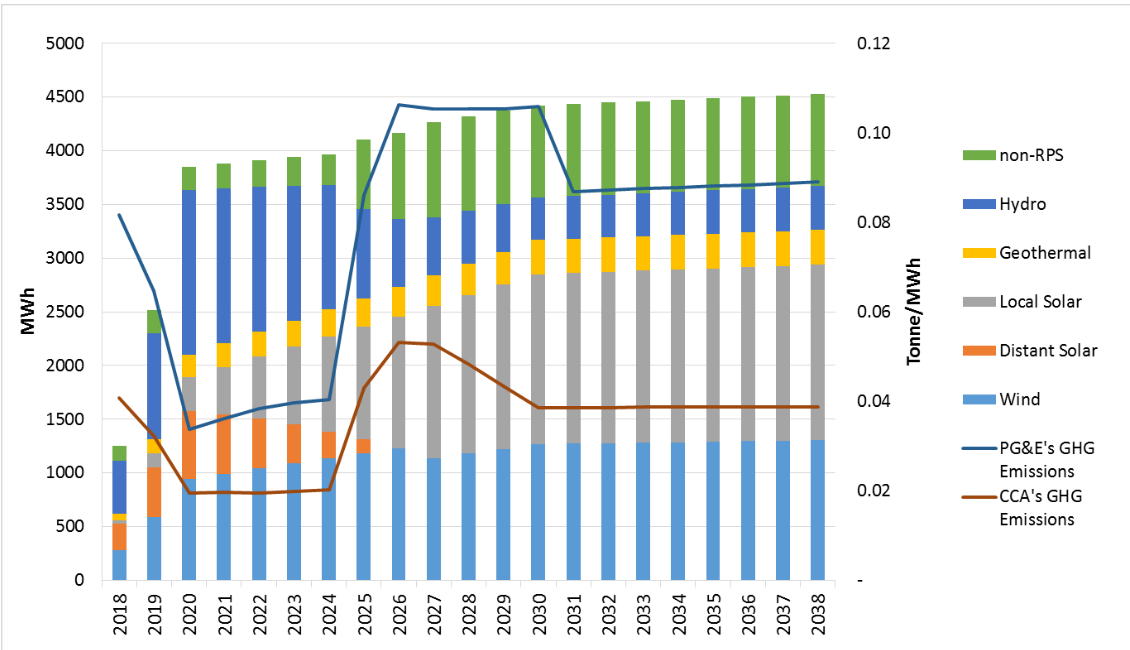
Table 11. Scenario 4 Savings for Residential CCE Customers

Residential	Monthly Consumption (kWh)	Bill with PG&E ($)	Bill with Contra Costa County CCA $)	Savings ($)	Savings (%)
2018	500	121	121	0	0%
2020	500	129	128	1	0.7%
2030	500	189	199	-10	-5%
2038	500	254	242	12	5%

GHG Emissions

The GHG emissions pattern for Scenario 4 is the same as Scenario 2 due to the scenarios having the same shares of GHG-free generation; the only difference being that local solar generation is assumed to replace solar supplies from more distant locations. Figure 22 compares the GHG emissions from 2018-2038 for the Contra Costa County CCE under Scenario 4 with what PG&E's emissions would be for the same load were no CCE formed.

Figure 22. Scenario 4 Contra Costa County CCE Supply Portfolio (vertical bars) and GHG Emissions (lines) ("Normal" PG&E Hydro Conditions)



Chapter 4: Sensitivity of Results to Key Inputs

In addition to the base case forecast described above, MRW has assessed alternative cases to evaluate the sensitivity of the results to possible conditions that would have an impact on Contra Costa County CCE's technical study. The metric considered to compare the alternative sensitivity cases to the base case is the differential between the annual average generation rates for PG&E bundled customers and for Contra Costa County CCE customers over the first ten years (2018-2028).[43] The latter 10 years were not included as they are both uncertain and skew the average results due to the widening gap between modeled PG&E's rates and the CCE's average cost.

The base-case analysis (Chapter 3 –Scenario 1) was developed as a reasonable and conservative assessment of the Contra Costa County CCE. In addition to the base case analysis, MRW analyzed alternative cases to address seven risks: (1) low participation, (2) higher local renewable power prices, (3) higher renewable power prices, (4) higher natural gas prices, (5) lower PG&E portfolio costs, (6) higher PCIA charges, and (7) a combination of these six risks (stress scenario).

Lower Participation Sensitivity

This sensitivity case evaluates the impact of lower participation on the CCE program. Lower participation could be due to a higher customer opt-out rates, or if some of the cities included in the study choose not to participate in the CCE program. If fewer customers join, CCE rates will generally be higher because about $7 million of annual CCE costs are invariant to the amount of CCE load. In the Lower Participation sensitivity, we assume that the load for the Contra Costa County CCE is 70% of the potential load.[44] Average administration costs in this scenario are 12% higher than in the base case scenario. These higher administration costs do not have a big impact on the CCE rates because administration costs are a small part of the total CCE rate (5% on average). The impact of this sensitivity case is to reduce the 2018-2028 average rate differential by 0.07¢/kWh relative to the base case.

Table 12. Lower Participation Sensitivity Results, 2018-2028

Period 2018-2028	Average Admin costs (¢/kWh)	Average rate differential (¢/kWh)
Base	0.45	1.86
Low participation	0.51	1.79

[43]The Contra Costa County CCE rate includes the PG&E exit fees (PCIA charges) that will be charged to CCE customers but does not include the rate adjustment for the reserve fund or other possible CCE activities.
[44] In the base case we considered 85% of the potential load.

Higher Local Renewable Power Prices Sensitivity

This sensitivity case evaluates the impact of higher local renewable power prices on the CCE's financial viability. As discussed in Appendix B, in the base case, the solar local renewable power price starts at $98/MWh in 2018 and it increases following the price curve. In the Higher Local Renewable Power Prices sensitivity, we assume that local renewable prices would be 20% higher than the base case prices. These higher prices affect only CCE rates for Scenario 3 and Scenario 4 (Scenario 1 and Scenario 2 do not include local generation), reducing the 2018-2028 average rate differential by 0.3¢/kWh relative to the base case.

Table 13. Higher Local Renewable Power Prices Sensitivity Results, 2018-2028[45]

Period 2018-2028	Average local renewable prices ($/MWh)	Average rate differential (¢/kWh)
Scenario 3	114.30	1.14
High local renewable prices	137.20	0.85

Higher Renewable Power Prices Sensitivity

This sensitivity case evaluates the impact of higher renewable power prices on the CCE's financial viability. As discussed in Appendix B, in the base case, renewable power prices are flat in nominal dollars through 2022, based on the assumption that projected declines in renewable development costs will offset increases associated with the expected expiration of federal renewable tax credits.[46,47] In the Higher Renewable Power Prices sensitivity, we assume that renewable prices would be flat in nominal dollars through 2022 if it were not for the tax credit expirations and add the impact of the tax credit expirations to the base case prices. Average renewable power prices in this scenario are 0-10% higher than in the base case scenario through 2021, about 20% higher in 2021 and 2022, and 30% higher after 2022 when the solar investment tax credit is reduced to 10%. These higher prices affect both the CCE and PG&E, but they have a greater effect on the CCE because PG&E has significant amounts of renewable resources under long-term contract. The impact of this sensitivity case is to reduce the 2018-2028 average rate differential by 0.35¢/kWh relative to the base case.

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[45] Results for Scenario 3.

[46] The Investment Tax Credit (ITC) which is commonly used by solar developers, is scheduled to remain at its current level of 30% through 2019 and then to fall over three years to 10%, where it is to remain. The federal Production Tax Credit (PTC), which is commonly used by wind developers, is scheduled to be reduced for facilities commencing construction in 2017-2019 and eliminated for subsequent construction.
U.S. Department of Energy. Business Energy Investment Tax Credit (ITC). http://energy.gov/savings/business-energy-investment-tax-credit-itc; U.S. Department of Energy. Electricity Production Tax Credit (PTC). http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc

[47] The base case forecast would also be consistent with a scenario in which the tax credit expirations are delayed.

Table 14. Higher Renewable Power Prices Sensitivity Results, 2018-2028

	Average RPS prices ($/MWh)	Resulting average rate differential (¢/kWh)
Base	53.2	1.86
High renewable prices	65.1	1.51

Higher Exit Fee (PCIA) Sensitivity

PG&E's PCIA exit fees are subject to considerable uncertainty. Under the current methodology, PCIA rates can swing dramatically from one year to the next, and this methodology is currently under review and may be adjusted in the coming years. MRW therefore evaluated a stress case in which PCIA rates do not fall after 2018, as anticipated in the base case, but instead remain at 2018 levels through 2028. This increases the 2028 PCIA by more than 300% of its base case value. The impact of this sensitivity case is to reduce the 2018-2028 average rate differential by 0.86¢/kWh relative to the base case.

Table 15. Higher PCIA Exit Fee Sensitivity Results, 2018-2028

	Average PCIA prices (¢/kWh)	Resulting average rate differential (¢/kWh)
Base	1.5	1.86
High PCIA	2.4	1.00

Lower PG&E Portfolio Cost Sensitivity

While changes to natural gas prices and renewable power prices affect both the CCE and PG&E, dampening the impact on the CCE's cost competitiveness, reductions to the costs to operate and maintain PG&E's nuclear and hydroelectric facilities would provide cost savings to PG&E that would not be offset by cost savings to the CCE. MRW considered a case in which PG&E's overall generation rates are 10% below the base case, driven by reductions to PG&E's nuclear and hydroelectric portfolio costs. Under such a scenario, the 2018-2028 average rate differential would be reduced by 1.12¢/kWh relative to the base case scenario.

Table 16. Lower PG&E Portfolio Sensitivity Results, 2018-2038

	Average PG&E Rate (¢/kWh)	Resulting average rate differential (¢/kWh)
Base	11.2	1.86
Low PG&E portfolio costs	10.1	0.74

Higher Natural Gas Prices Sensitivity

Natural gas prices have been low and relatively steady over the last few years, but they have historically been quite volatile and subject to significant swings from local supply disruptions (e.g., Hurricanes Katrina and Rita in 2005). MRW analyzed a gas price sensitivity case using the U.S. Energy Information Administration's High Scenario natural gas prices forecast,[48] which is on average 50% higher than MRW's base case forecast for the period 2018-2028. Natural gas price increases affect power supply costs for both a Contra Costa County CCE and PG&E; however, the nuclear and hydroelectric capacity in PG&E's resource mix makes PG&E less sensitive than a Contra Costa County CCE to changes in natural gas prices. The net effect of higher natural gas prices is therefore to increase CCE rates relative to PG&E rates[49] (i.e., reduce the average rate differential). Under the sensitivity conditions considered, the 2018-2038 average rate differential decreases relative to the base case by 1.68¢/kWh.

Table 17. Higher Natural Gas Prices Sensitivity Results, 2018-2028

	Average PG&E Rate (¢/kWh)	Resulting average rate differential (¢/kWh)
Base	11.2	1.86
Low PG&E portfolio costs	10.1	0.18

Stress Case and Sensitivity Comparisons

All rate differentials (i.e., the CCE's competitive positions) are lower in the sensitivity cases than in the base case scenario for all years from 2018 to 2028 (**Table 18**). To evaluate a more extreme scenario, MRW developed a stress case that combines all the sensitivity cases: (1) low

[48] U.S. Energy Information Administration. "2015 Annual Energy Outlook," Table 13
[49] For Scenarios 2 and 4 the high gas natural prices case has less negative impact due to the high proportion of renewable generation.

participation, (2) higher local renewable power prices, (3) higher renewable power prices, (4) higher natural gas prices, (5) lower PG&E portfolio costs, and (6) higher PCIA charges. The 2018-2028 average rate differential for this stress case is negative, at -4.08¢/kWh, meaning that CCE customer costs would exceed PG&E customer costs under this scenario.

Table 18. Stress Test Results, 2018-2028

	Resulting average rate differential (¢/kWh)
Base	1.86
Stress Scenario	-2.3

Figure 23. Difference Between PG&E Customer Rates and CCE Customer Rates Under Each Sensitivity Case, 2018-2028[50]

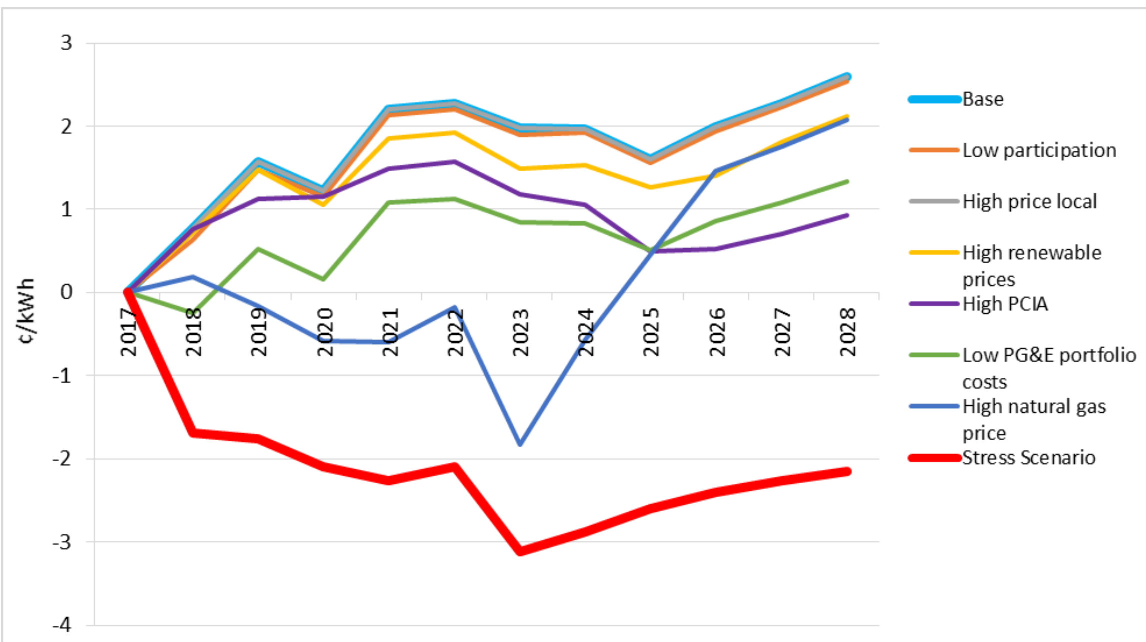


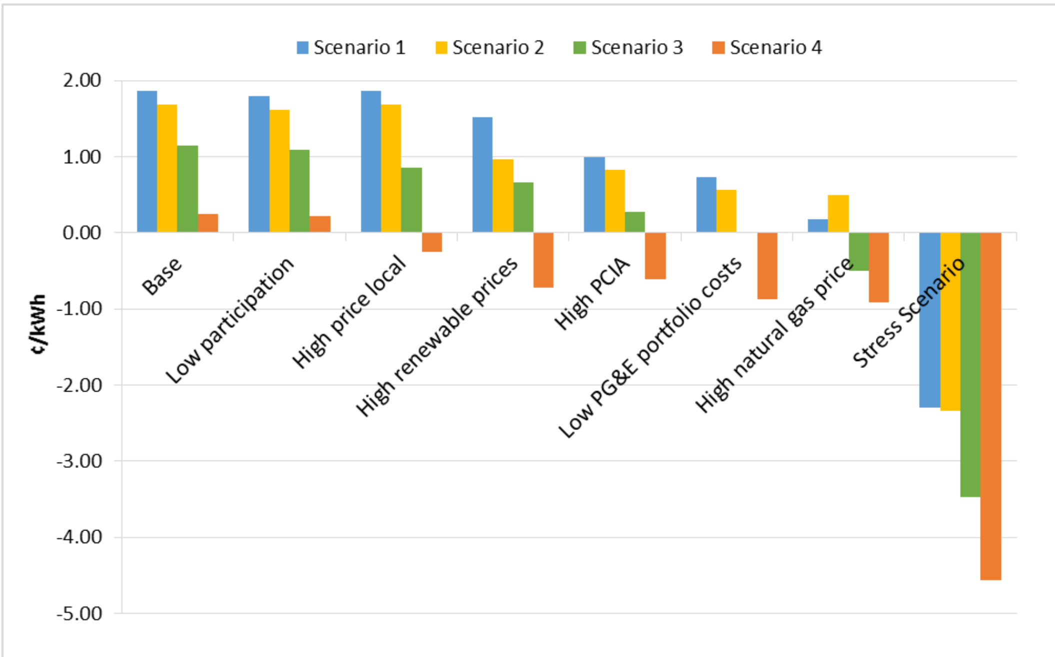
Figure 23 shows the difference between the PG&E customer rates and the Contra Costa County CCE customer rates (including exit fees) in the base case, and in each of the sensitivity scenarios, for each year from 2018 to 2028. As Figure 23 illustrates, CCE customer rates are lower than PG&E customer rates in each of the individual sensitivity cases in each year. For the High Natural Gas Price sensitivity case, in 2023 the rate differential drops due to an increase on the

[50] The chart plots the sensitivity cases for Scenario 1, therefore it does not reflect the effect of the High Price Local sensitivity (it only applies to Scenario 3 and 4).

PCIA, as the PCIA is highly sensitive to the natural gas prices. Under the Stress Scenario case, the rate differential is negative for each year (i.e., CCE rates are higher than PG&E generation rates).

The results shown above reflect the Minimum RPS Compliance supply scenario (Scenario 1). MRW additionally evaluated each sensitivity scenario under the four alternative supply scenarios: (1) Minimum RPS Compliance, (2) Accelerated RPS, (3) Minimum RPS Compliance plus Local Procurement, and (4) Accelerated RPS plus Local Procurement. Figure 24 depicts the average rate differentials for 2018-2028 for each sensitivity case under the four supply scenarios.

Figure 24. Difference Between PG&E Customer Rates and CCE Customer Rates Under Each Sensitivity Case and Supply Scenario, 2018-2028 Average



Looking at 2018-2028, Scenario 1 (Minimum RPS Compliance) is the least costly scenario for the CCE, and therefore has the best rate differential under most of the sensitivity cases considered.[51] Scenario 2 (Accelerated RPS), though still quite competitive with PG&E, fares slightly worse, with a rate differential approximately 10-20% lower than in Scenario 1 for most of the sensitivity cases considered. The one exception is the High Natural Gas Price sensitivity case, in which Scenario 1 has worse results than Scenario 2. This is due to the higher gas-fired generation content in Scenario 1, which makes the supply portfolio more susceptible to volatility in natural gas prices than Scenario 2. For most of the sensitivity cases, rate differentials for

[51] This is only looking at the period 2018-2028. From 2028-2033 the rates show the same pattern between the four scenarios. If we consider the period 2033-2038, Scenario 2 would be the least costly scenario. After 2033 the prices of renewable generation are expected to be lower than the wholesale electric market, which makes Scenario 2 less costly than Scenario 1 in the period 2033-2038.

Scenario 3 are lower than Scenario 1 and Scenario 2. Scenario 4 is the costliest scenario, with rate differentials much lower than the other three scenarios.

In the stress case, Contra Costa County CCE customer rates exceed PG&E customer rates on average over the 2018-2028 period for all four scenarios, with the negative rate differential being highest in Scenario 4 at -4.5¢/kWh.

Conclusions

Under Scenarios 1, 2 and 3, Contra Costa County CCE customer rates compare favorably to PG&E rates in all years from 2018 to 2038. As modeled, in Scenario 4 Contra Costa County CCE customer rates would be higher than PG&E rates from about 2025 and 2030. Under Scenarios 1 and 2 (simple RPS compliance), Contra Costa County CCE customer rates remain below PG&E rates under all but the most extreme sensitivity case considered. Scenario 3 rates could meet or beat PG&E's under all but the high natural gas and stress cases. Under the stress case, irrespective of the supply scenario considered, CCE rates are higher than PG&E rates. While the stress case may appear extreme given that it involves seven adverse sensitivities simultaneously occurring, cost volatility in the power industry is well established, and the possibility of adverse conditions arising in an isolated year should be understood and planned for in any CCE venture.

Chapter 5: Macroeconomic Impacts

This chapter discusses the job impacts within Contra Costa County for each of the four scenarios. All four scenarios modeled showed positive economic and job impacts. The mix and amount of jobs created would depend upon policy decisions made by the CCE board, primarily trading off the economic stimulus from lower electricity bills versus the direct jobs created by local (higher cost) renewable energy projects sponsored by the CCE.

To understand just how job impacts can come about, and the extent of those changes (positive or negative), a brief description of elements associated with the CCE and how they influence the existing economy is provided.

How a CCE interacts with the Surrounding Economy

The establishment and operation of a CCE creates a new set of spending elements (also referred to as "demands") as a community changes the type of electricity generation they want to purchase, where the new mix of generation is to be located, adjustments necessary for existing generating assets of the provider utility, and implications on customers' bills because of retail rate differentials. Some of these new elements have temporary effects, while others have long-term effects. Investment in locally sited solar will result in temporary direct creation of jobs whereas subsequent *maintenance* will support some on-going direct jobs. Regardless of the duration, when a direct job is created in a sector, there will be a multiplier response on "backwardly-linked" jobs with supplier businesses if the supplier is present in the economy. The new elements include:

- **Administration** – direct jobs, long-term effect. County staffing, professional-technical services and I/T-database services
- **Net Rate Savings (or bill savings)** – long-term effect. County households have an increase in their spending ability, County commercial and industrial energy customers experience a reduction in their costs-of-doing business which makes them each more competitive, garnering more business that requires more employees, and municipal energy customers can provide more local services which require more local government staff.
- **New Renewable Capacity Investment within County & Surrounding counties** – direct jobs, short-term, two of the four scenarios.
- **New Renewable Operations within County & Surrounding counties** – direct jobs, long-term, two of the four scenarios.
- **Net Generating Capacity and Operations offsets for PG&E outside of county** – direct jobs, short and long-term, none because we are not focused on the *rest of California* economy.

To frame expectations around how many direct jobs can be created in the County from the above CCE elements, consideration must be given to (a) how much of the spending associated with the CCE scenario is fulfilled by a within-county business or resident workforce, and (b) what do these locally-fulfilled dollars represent in terms of current annual County business activity (e.g., is this a large spending event?).

Job Impacts of Proposed CCE Scenarios

We examine each of the four scenarios for their influence on the County economy and the economy of the four surrounding counties combined (a ring region comprised of Alameda, Sacramento, San Joaquin, and Solano counties). The basis for including the surrounding counties is (i) interdependence of the economies in terms of business-to-business transactions (in part due to proximity) and labor commuting flows (both in and out), as well as (ii) the siting of 50 percent of the proposed CCE funded small-scale solar projects beyond Contra Costa County. The scenario structures assume no electric customer participation from beyond Contra Costa County therefore the proposed *bill savings* are allocated across customer segments solely within Contra Costa County.

The possible sources of *initial* job change in any of the scenarios include:

- CCE Administration *spending* 2018 to 2038 (within Contra Costa County)
- Bill Savings *less* Customer's expense for on-site solar deployed 2018 to 2038 (within Contra Costa County)
- Investment in small-scale Solar 2018 to 2030 (Contra Costa and the 4-county ring region)
- O&M spending on small-scale Solar 2018 to 2038 (Contra Costa and the 4-county ring region)

Only scenarios 3 and 4 include investment for small-solar projects in Contra Costa County and the surrounding region of counties. Once each regional economy experiences its initial change related to any of the above scenario elements, a macroeconomic forecasting tool (the REMI model[52]) captures impacts from inter-regional transactions (of commuters, of business sales), and impacts from changes in Contra Costa County's relative *cost-of-living* and *cost-of-doing business* resulting from bill savings, and impacts associated with *multiplier effects*.

Overview of Scenario Effects

It is helpful to understand how the various scenarios "stack up" in terms of the four sources that will exert an influence on the local economies. Table 19 presents the cumulative (2018 to 2038) stimuli - bill savings, administrative spending, and where relevant, demands related to investment, O&M. The amounts are a roll-up of nominal values. Scenario 1 poses the greatest amount of Rate Savings for County CCE customers ($2,390 million), and Scenario 4 poses the largest amount of solar investment *demand* ($827 million) for in-county installations. Ensuing O&M spending (Scenarios 3 and 4) will increase as the investment *demand* increases. None of the displaced renewable capacity by PG&E (investments under the "business-as-usual" or "without CCE" case) occurs in either Contra Costa or the surrounding 4 counties.

[52] Regional Economic Models, Inc. of Amherst, MA. www.remi.com

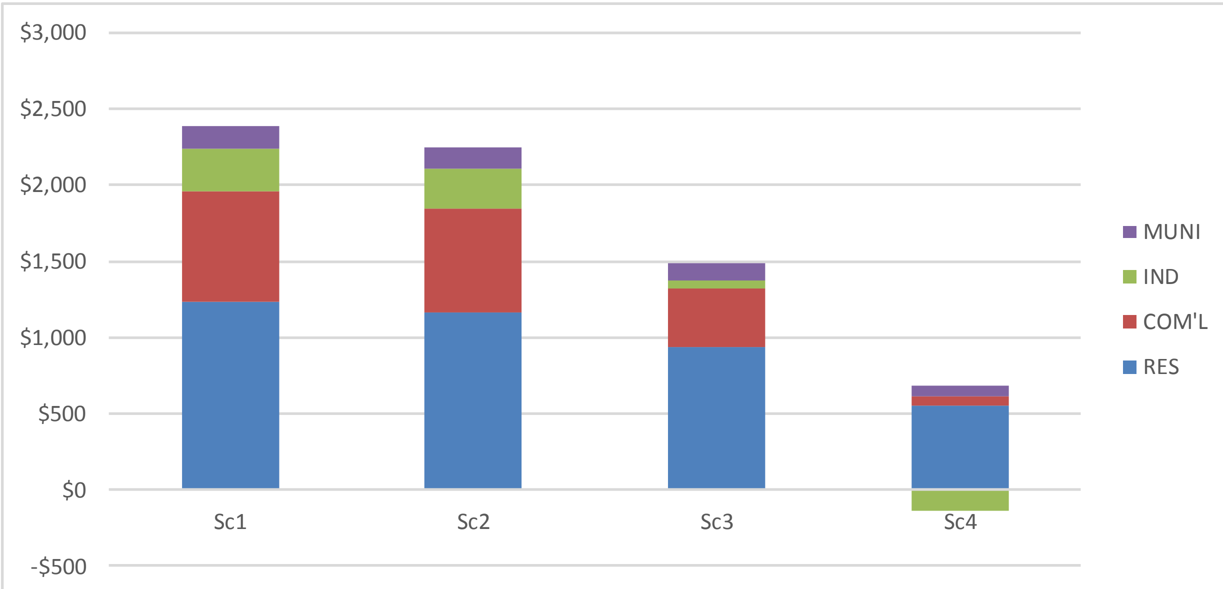
Table 19. CCE Scenario Economic Characteristics (2018-2038, Millions of nominal dollars)[53]

Scen.	Net Rate savings County customers	CCE Small Solar Investment		CCE Small Solar O&M	
		Contra Costa County	Neighboring Counties	Contra Costa County	Neighboring Counties
1	$2,390	$0	$0	$0	$0
2	$2,251	$0	$0	$0	$0
3	$1,485	$456	$456	$234	$234
4	$542	$827	$827	$375	$375

Figure 25 presents the estimated *net* rate savings for various customer-segments in the County by CCE scenario. The rate savings benefit accrues foremost to the residential segment, followed by the commercial segment. The municipal segment has fairly constant rate savings regardless of scenario. In addition to the magnitude of overall net rate savings and local solar-related business opportunities, this segment distribution across customer segments influences part of the job impact response (amidst solar investments). Households spend money saved on electric bills on other consumer basket items, which would include a mix of goods and services, some local, some imported, which all rely on different jobs at different wages. Commercial or industrial electric customers experience a savings as making their operations more cost competitive, which returns some positive (though not equal across all type of activities) market share growth (e.g., more sales which means more jobs and other inputs to their operations). Municipal segment savings allow the state/local government entity to redirect dollars into other forms of public spending.

[53] *Net* Rate Savings are net of customer out-of-pocket for on-site solar additions under Scenarios 3 and 4. For the County projects, 25 percent of the investment is paid by *Industrial* customers, 25 percent by *Commercial* customers, with the balance funded by outside investors. Small-solar projects in the surrounding counties are assumed to be funded by outside investors. Under scenarios 1 and 2 *net* is equal to gross rate savings.

Figure 25. Cumulative net Rate Savings in Contra Costa County, Proposed CCE structures



The opportunity for the small-solar investment episode (2018 through 2030), for scenarios 3 and 4, to generate "within region" job requirements is determined by how much of the investment dollars connect with (procure from) 'within region' construction labor and businesses that provide project components. The allocations of small-solar investment dollars into these two major types of purchases (with additional breakdown on non-labor expenditures) is done using the National Renewable Energy Laboratory (NREL) Jobs and Economic Development Impact (JEDI) small-solar PV JEDI model[54] (CA) allocation. As shown in Table 20 for scenarios 3 and 4, no less than 50 percent of the various budgets enlists local workforce, and firms that provide supplies or services.

[54] The Jobs and Economic Development Impact (JEDI) models are user-friendly screening tools that estimate the economic impacts of constructing and operating power plants, fuel production facilities, and other projects at the local (usually state) level. JEDI results are intended to be estimates, not precise predictions. See: http://www.nrel.gov/analysis/jedi/about_jedi.html

Table 20. Local Fulfillment of CCE Budgets (millions of nominal dollars)

	CCA Admin	Solar Invest	Solar O&M	CCA Admin	Solar Invest	Solar O&M
		Scenario 1			Scenario 3	
Budget	$316	*N/A*	*N/A*	$316	$456	$233
In-County						
locally procured	$189	*N/A*	*N/A*	$189	$234	$146
% capture local	60%	*N/A*	*N/A*	60%	51%	63%
Surrounding Counties						
locally procured	*N/A*	*N/A*	*N/A*	*N/A*	$234	$146
% capture local	*N/A*	*N/A*	*N/A*	*N/A*	51%	63%
		Scenario 2			Scenario 4	
Budget	$316	*N/A*	*N/A*	$316	$ 827	$375
In-County						
locally procured	$189	*N/A*	*N/A*	$189	$425	$235
% capture local	60%	*N/A*	*N/A*	60%	51%	63%
Surrounding Counties						
locally procured	*N/A*	*N/A*	*N/A*	*N/A*	$450	$219
% capture local	*N/A*	*N/A*	*N/A*	*N/A*	51%	63%

Resulting Impacts on Jobs

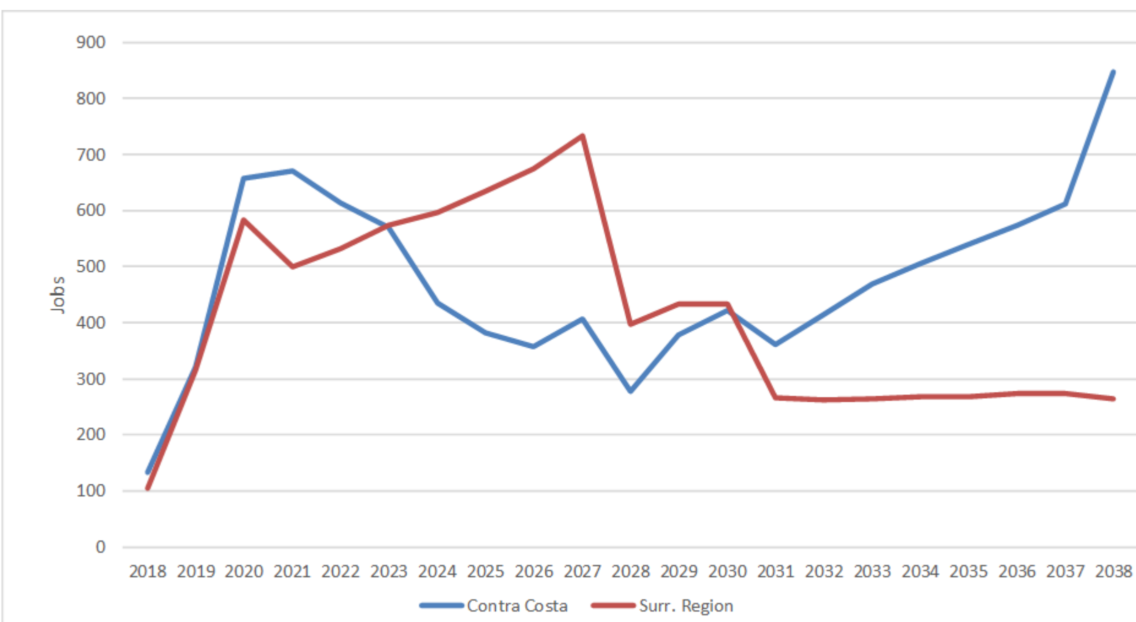
This section will present several views of the job impacts by scenario. As shown in Table 21, Scenario 1 yields the largest annual job impact for the County over the interval – the result of the maximum rate savings under the CCE program. Job impacts are not limited to the direct job requirements from a CCE but include jobs resulting from *multiplier effects* and *competitiveness effects*. Scenario 4 – with the smallest of *net* rate savings for the County's electric customers poses the largest investment for small -solar across the 5-county economy. This compensates for the reduced role of the rate savings and thus Scenario 4 yields an annual job gain for the 5-county economy, 886 jobs (compared to Scenario 1 with 731). The largest absolute job gain is in Scenario 3, with a total of 922 annual average jobs. As the amount of small solar investment increases (with subsequent O&M spending to follow), the percent of job impact that occurs within the surrounding multi-county region increases (Scenario 4 has 44%). The County's annual job increase under Scenario 4 however is moderated when compared to Scenario 1. This is understood by (i) all CCE customers' realizing smaller rate savings when the CCE attempts to invest in *local* solar, combined with (ii) commercial/industrial businesses in the County picking up 50 percent of the solar investment cost. Also, influencing the "surrounding county region" job impact is the fact that a neighboring economy (the County) is experiencing lower electric bills (regardless of the magnitude) and a solar installation "boom" – namely, economic stimulating events. This can create a positive bounce for the surrounding counties on some of the background business (supplier) transactions as well as with working-age households who commute into the County (this point is illustrated in Figure 26). And when the surrounding region is host to its own solar installation boom, this will engage the Contra Costa County economy as well.

Table 21. Average Annual Employment Impacts 2018 through 2038 (Jobs)

Scenario	Contra Costa	Surrounding 4 Counties	All 5 counties	% in Region
1	681	50	731	7%
2	571	48	619	7%
3	654	268	922	29%
4	474	412	886	44%

For Scenario 4 (with the smallest *net* rate savings and the highest local solar-investment/O&M spend) a time-path of the resulting job impacts is shown in Figure 26. To be clear, the results are not depicting *cumulative* job impacts, simply a plot of each year's resulting impact. After 2030, no more solar installations occur in either region.[55] The surrounding region remains slightly buoyed with job impacts due to some continued O&M spending and feedback from the Contra Costa economy that is still benefitting now from *gross* rate savings (no more project expenses) and some O&M spending.

Figure 26. Scenario 4 – Annual Job Impacts, 2018 to 2038



[55] This is because the targeted renewable penetration was met and no new generation is needed by the CCE. If the study looked further out, then replacement solar would begin to have an effect and generate jobs.

Figure 27 helps explain ‘the dip’ in the above *blue* series of positive job impacts *(for Contra Costa*) between 2024 and 2030. The estimated forecast of *net* rate savings follows such a trajectory (becoming *negative* between 2023 and 2030, when some customers bear a portion of the investment cost plus CCE rates are slightly higher than PG&E’s) and even the *local* capture on the solar investment comes off a local maximum in 2020 and a global maximum in 2027 (the latter occurs in the surrounding region as well).

Figure 27. Scenario 4 – Contra Costa’s “Local” Benefit

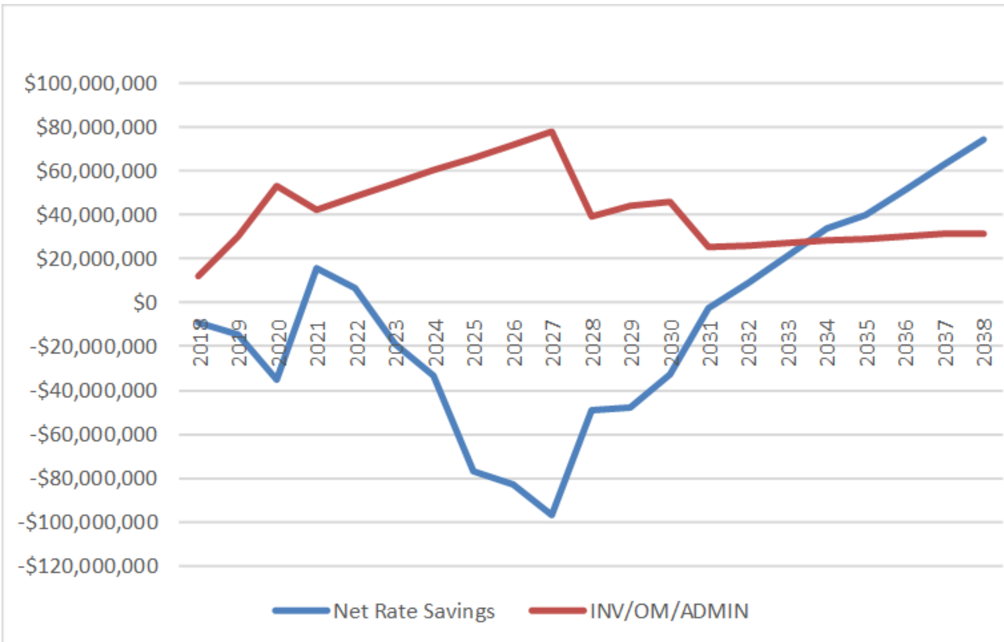
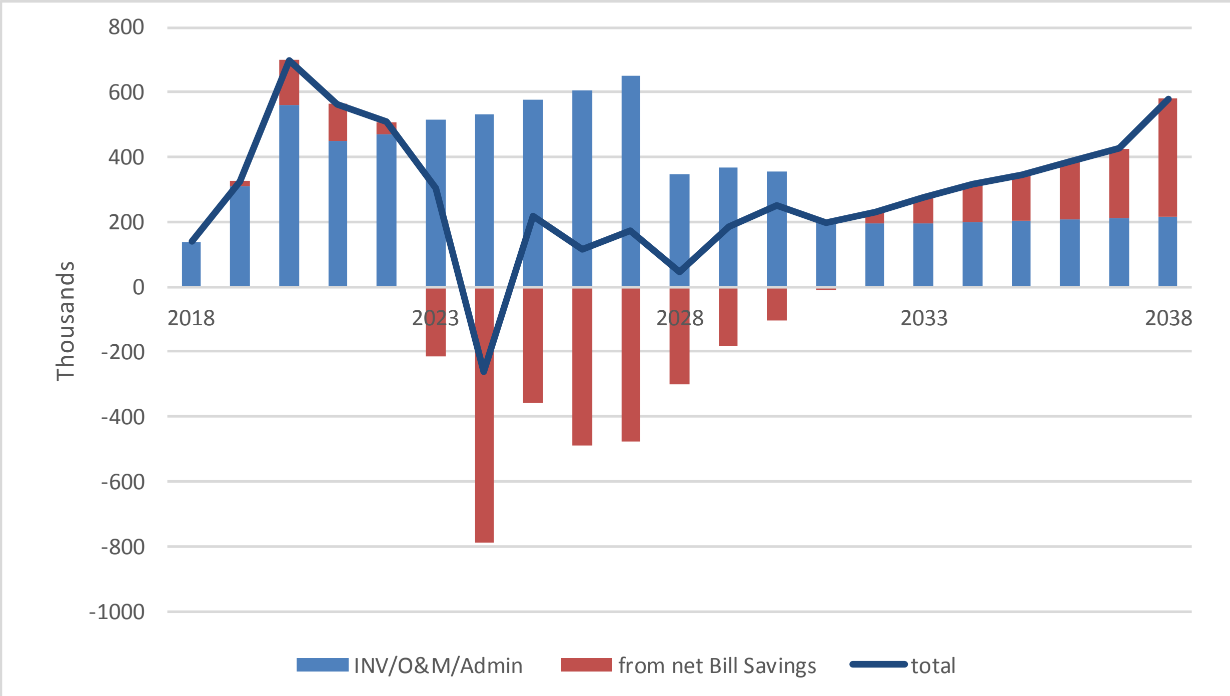


Figure 28 shows what contributes to Contra Costa’s job impact under Scenario 4. The dark blue line is the line from Figure 26. Through 2030, the largest influence on the County’s *positive* job impacts is the stimulus of solar project investment. Afterwards it is the role of *net* Rate Savings exerted through the customers’ roles in the local economy that creates local jobs.

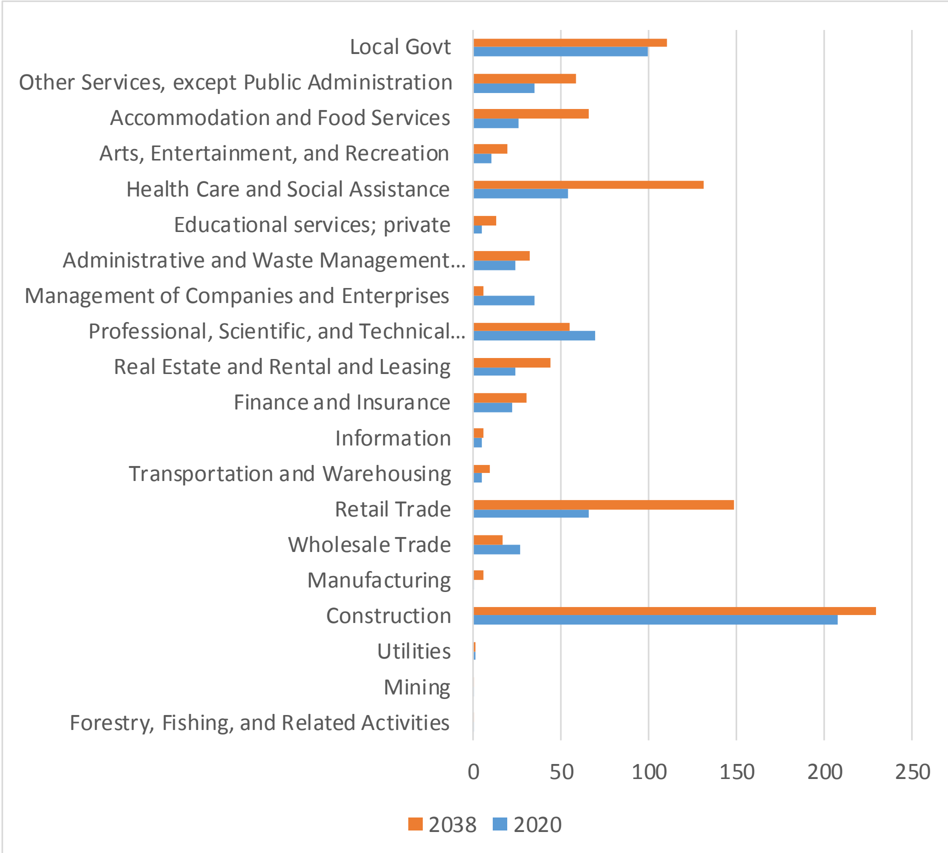
Figure 28. Scenario 4 – Contra Costa Job Impact by Source



A look at two points in the policy interval illustrates the types of jobs that comprise the impact results. In 2020 there are about 700 additional jobs (when solar investment is at a maximum with little of the *net rate savings* realized*)* and in 2038, about 600 additional jobs in the County (after the investment hang-over is past and only a small influence is exerted through O&M and administrative spending, and the County economy is still experiencing a ramp up of rate savings).

Figure 29 shows a pattern and an order of magnitude for each of the *snapshot* years that is indicative of the major CCE influence on the County's industry base. In 2020, County job additions are explained foremost by the predominant effect emanating from the CCE scenario – namely solar project investment and program administration (net rate savings are *negative* at this point as a result of C/I customers paying for part of the solar investment cost). So, jobs occur in *Construction*, in State/Local *Government*, in *Professional Technical Services*, and with *Wholesale suppliers*. Project developer overhead payments (part of the investment cost) is why job additions are showing for *Management of Companies and Enterprises*. But not all of the job additions in these sectors are directly related to solar installations. Some of these – as well as jobs gains in other non-investment sectors like health care, and food establishments, and retail – are the result of the initial labor income gains (construction paychecks) which drives added household spending (the *induced* stage of economic multiplier effects), and some are the result of increases in "within county" business-to-business transactions and elevated business needs from the adjacent region (the *indirect* stage of multiplier effects.)

Figure 29. Scenario 4 - Jobs added Among Contra Costa Sectors, 2020 and 2038



In 2038, (the orange series) the predominant 'economy' effect from the CCE is the *net* rate savings with a majority benefitting the *residential segment*. Households will redirect these savings into additional household spending (e.g., health care, retail, food establishments). But the municipal segment receives savings as well which drives additional public spending and requires some growth in staff in addition to the local government staff to administer the CCE (an average of 23 *administrative* staff). Commercial and industrial sectors also experience some job increases as their bill savings improve their bottom lines and grow their respective market shares for business. The pronounced gain in local government jobs is more than the (averaged) 23 staff mentioned above. By 2038 the County will have retained a significant number of its working-age residents that would otherwise have out-migrated (under the business-as-usual case) due to a combination of *relative* employment opportunities and inflation adjusted wages. The CCE activity creates job opportunity, mitigates in-county inflation (vis a vis bill savings) so there is real wage appreciation, and helps stem the tide of out-migration of key working-age cohorts. This further bolsters the positive population growth the County was forecast to have (under the BAU case), and local government spending (and staffing) increase on a *per capita* basis. In addition, the S/L government activity increases as the productive capacity of the County grows (in terms of dollars of gross regional product). The *Construction* sector posts strong job increases but now it is more the response to growth in the County (due to CCE influences) and this sector is key during investment (for both residential and non-residential structures) responses to close the gap between actual and optimal capital requirements in a growing economy.

Allocation of Earned Income Gains

A majority but not all jobs added in Contra Costa County will be held by the County's working-age resident households. The same is true for jobs added in the 4-county surrounding region. Which means the household spending effects from the take-home pay on the above impacted jobs occur where the worker *resides*. The above job impacts are measured by *place-of-work.* The commuter from another county registers the induced effects of their earned income on a *place-of-residence* basis.

Again, we focus on Scenario 4 in the year 2020 (year of maximum investment activity that is split 50:50 across both regions). Before we even allocate the impacts across the County boundary, it is helpful to reveal the broad commuting propensity (this is not industry-specific but rather across all activities within an economy) for these two interconnected regions. These relationships are captured in County data on personal (earned) income flows and the journey-to-work data – both federally collected. Table 22 shows the extent of *linkage* on earned income generated in one region and where its workers reside.

Table 22. Earnings-Commuter Reliance between Contra Costa County and the Surrounding region

		Earnings Place-of-Work	
		Contra Costa	Surrounding region
Worker resides	Contra Costa	79%	8.5%
	Surrounding Counties	15%	73%
	Elsewhere	6%	18%
		100%	**100%**

Based on each of the model region's reliance on jobs situated beyond their border there will be "earned income" imported for both Contra Costa and the surrounding region since both economies experience job increases under the CCE activity. For workplace earnings generated in Contra Costa County, 15 percent is earned by residents of the surrounding counties (we ignore the *elsewhere* because it is not part of our macroeconomic consideration). Likewise, of workplace earnings generated in the surrounding counties region, 8.5 percent is by commuters from Contra Costa County. Table 23 shows for 2020 the extent of extra jobs and earnings that will be held by a worker who resides in the other region. Of the 700 jobs added in Contra Costa County in 2020, 83 of these jobs (and $7 million of earnings) belong to commuters from the adjacent region. Of the 584 jobs added in the surrounding region in 2020, 41 of these jobs (and $4 million of earnings) belong to commuters from Contra Costa County.

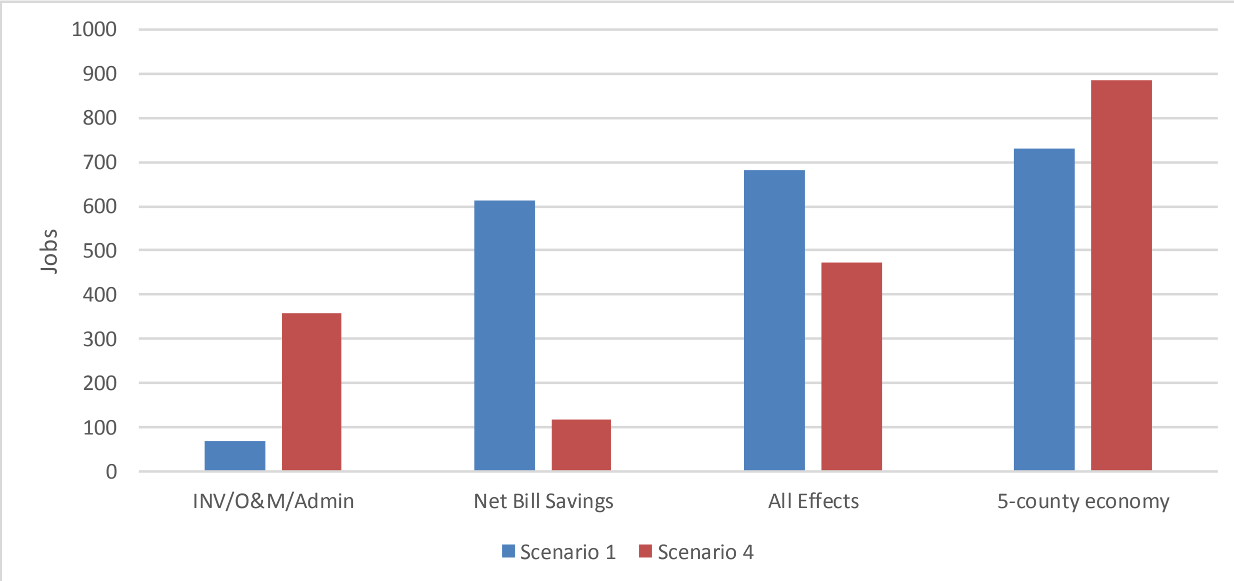
Table 23. Scenario 4 - Earnings Impact by Place-of-Residence, 2020[56]

Scenario 4, Year 2020	Place-of-Work	
	Contra Costa County	Surrounding region
Job impact	700	580
Earnings impact	$48 million	$42 million
Earnings per Job	$86,000	$87,500
% Commuter earnings (Surrounding counties)	15%	na
% Commuter earnings (Contra Costa)	Na	8.5%
Impact Commuter earnings for Surrounding counties	$7 million	na
Impact Commuter earnings for Contra Costa	Na	$4 million
Equiv. # of Surrounding County Commuters	83	na
Equiv. # of Contra Costa Commuters	Na	41

Last, a high-level decomposition of the job impact result in the County is shown in Figure 30 for Scenario 1 (the highest customer savings, no investment in local solar capacity) and Scenario 4. Under Scenario 1 the County realizes most job creation through the effects of rate savings on the County's economy. This response is 5-fold of what Scenario 4 would show as a job impact from rate savings. On the other hand, Scenario 4 exhibits a 5-fold job creation impact from the combined *investment/O&M/administration* effects. Including job creation impacts in the adjacent region of the four surrounding counties, Scenario 4 produces over 100 more jobs (average annual) than Scenario 1. This is predominantly explained by the surrounding region being the location for 50 percent of the small-solar investment that the CCE might choose to fund.

[56] Earnings per job are weighted estimates.

Figure 30. Average Annual Job Impact in Contra Costa County by Source



Conclusion

A CCE can also offer positive economic development and employment benefits to the County. At the peak, the CCE could create approximately 500 to 700 new jobs in the County plus additional jobs in neighboring counties. For Scenarios 1 and 2, the main driver behind the job growth is the general economic stimulus from injecting more dollars into the local economy via reduced electric rates. When costlier, locally-built renewable projects are emphasized, like in Scenarios 3 and 4, the general economic stimulus driver is replaced by the direct jobs and stimulus created by locally-sited and sourced renewable projects.

Because Contra Costa County's economy is not isolated, CCE formation can have positive effects in neighboring counties, too. This is particularly for the Scenarios emphasizing locally-built renewables, where workers would commute to jobsites in Contra Costa County.

Chapter 6: Other Risks

Aside from the risks identified above, the CCE or the political jurisdictions that are part of the CCE could be at risk for several other reasons. This section addresses some of those risks, which are summarized in Table 24.[57]

Table 24. Summary of CCE Risks

Risk	Magnitude	Mitigation
Financial Risks to CCE Members	Low	Keep CCE JPA's financial obligations separate from jurisdiction's
Procurement-Related Risks (i.e., can't meet rate or GHG targets)	Medium-low	Enter into balanced portfolio of power contracts
Legislative and Regulatory Risks	High	Monitor and advocate at Legislature and CPUC
PCIA Uncertainty	High	Establish rate-stabilization fund to account for volatile PCIA
PCIA Policy Uncertainty	High	Monitor and advocate at Legislature and CPUC
Availability/price of low-carbon resources	Medium	Enter into balanced portfolio of power contracts
Bonding Risk	Low	Monitor and advocate at CPUC

Financial Risks to CCE Members

A CCE is effectively an association of various political subdivisions. The formation documents for the CCE define the rights and responsibilities of each member of the CCE. Given the large number of political subdivisions that might participate in a Contra Costa County CCE, MRW assumes that the Contra Costa County CCE would be formed under a Joint Powers Authority, in much the same way as MCE and Sonoma Clean Power.

The CCE will ultimately take on various financial obligations. These include obtaining start-up financing, establishing lines of credit, and entering into contracts with suppliers. Because a CCE will take on such financial obligations, it is likely very important to the prospective member political subdivisions that the financial obligations of the CCE cannot be assigned to the members.

[57] Note that this section does not provide legal opinion regarding specific risks, especially those related to the formation or the structure of the Joint Powers Authority under which MRW assumes the CCE will be established.

Thus, it is critical that the Joint Powers Authority and any other structuring documents are carefully drafted to ensure that the member agencies are not jointly obligated on behalf of the CCE (unless a member agency chooses to bear such obligations). The CCE should obtain competent legal assistance when developing the formation documents.[58]

Nonetheless, starting up a CCE often requires a credit-worthy entity to backstop its initial financing. Some, such as CleanPowerSF, use the balance sheet from its existing power enterprise to backstop initial financing. Others have relied upon their host county as a backstop to initial financing. For example, MCE's initial bank loans for working capital were guaranteed by Marin County and the Town of Fairfax. After approximately six years, the CCE had demonstrated its creditworthiness and the guarantees were lifted. Still, the JPA cannot place any financial obligations or risks onto any of its members without that member's approval.

Procurement-Related Risks

Because a CCE is responsible for procurement of supply for its customers, the CCE must develop a portfolio of supply that meets the resource preferences of its customers (e.g., ratio of renewable versus non-renewable supply) while controlling risks (e.g., ratio of short-term versus long-term purchase agreements) and meeting regulatory mandates (e.g., resource adequacy and RPS requirements). Thus, it is tempting to assume that customers would prefer a fully hedged supply portfolio. However, such insurance comes at a cost and a CCE must be mindful of the potential competition from PG&E. Thus, the CCE's portfolio must be flexible while meeting the needs of its customers.

The CCE will likely need to negotiate a flexible supply arrangement with its initial set of suppliers. Such an arrangement is important because the CCE's loads are highly uncertain during CCE ramp-up. Without such an arrangement, the CCE faces the risk of either under- or over-procuring renewable or non-renewable supplies. Excessive mismatches between supply and demand of these different products could expose the CCE's customers to significant purchases or sales in the spot markets. These spot purchases could have a large impact on the CCE's financials.

The CCE will by necessity have to procure a certain amount of short-term supplies. These short-term supplies bring with them price volatility for that element of the supply portfolio. While this volatility is not unexpected, the CCE must be mindful that such volatility could increase the need for reserve funds to help buffer rate volatility for the CCE's customers. Funding such reserve funds could be challenging in this time of low gas prices (resulting in high PCIA charges).

The CCE will be entering the renewable market at an interesting time. While all LSEs must meet the expanded RPS targets by 2030, at least the IOUs are currently over-procured relative to their 2020 RPS targets. Whether the IOUs will attempt to sell off some of their near-term renewable supplies is unknown. However, if the IOUs believe that this is a good time to acquire additional

[58] Cities such as El Cerrito and Benicia conducted legal analyses when they were considering joining MCE. which should also be consulted.

renewables, the CCE could face stiff competition for renewable supplies, meaning that the green portfolio costs for the CCE might be higher than expected.

Finally, it should be noted that as greater levels of renewables are developed to meet the State's very aggressive RPS goals, it is possible that the traditional peak period will change. Adding significant amounts of solar could depress prices during the middle of the day. This could result in the need to try to sell power to out-of-state market participants during the middle of the day, possibly even at a loss. It could also result in the curtailment of renewable resources (even resources owned or controlled by the CCE). This could force the CCE to acquire greater levels of renewable supplies, thereby increasing costs.

Legislative and Regulatory Risks

As noted above, the CCE must meet various procurement requirements established by the State and implemented by the CPUC or other agencies. These include procuring sufficient resource adequacy capacity of the proper type and meeting RPS requirements that are evolving.[59] Additional rules and requirements might be established. These could affect the bottom line of the CCE.

PCIA Uncertainty

Assembly Bill 117, which established the CCE program in California, included a provision that states that customers that remain with the utility should be "indifferent" to the departure of customers from utility service to CCE service. This has been broadly interpreted by the CPUC to mean that the departure of customers to CCE service cannot cause the rates of the remaining utility "bundled" customers to go up. To maintain bundled customer rates, the CPUC has instituted an exit fee, known as the "Power Charge Indifference Adjustment" or "PCIA" that is charged to all CCE customers. The PCIA is intended to ensure that generation costs incurred by PG&E before a customer transitions to CCE service are not shifted to remaining PG&E bundled service customers.

Even though there is an explicit formula for calculating the PCIA, forecasting the PCIA is difficult, because many of the key inputs to the calculation are not publicly available, and the results are very sensitive to these key assumptions. For PG&E, the PCIA has varied widely; for example, at one time the PCIA was negative.

Current CCEs have chosen to have customers bear the financial risk associated with the level of exit fees they will pay to PG&E. Thus, for a customer taking CCE service to be economically better off (i.e., pay less for electricity), the sum of the CCE charges plus the PCIA must be lower than PG&E's generation rate.

This risk can be mitigated in two ways. First, as discussed in more detail elsewhere, a rate stabilization fund can be created. Second, the CCE can actively monitor and vigorously participate in CPUC proceedings that impact cost recovery and the PCIA.

[59] Rules to establish RPS requirements under the new 50% RPS mandate are currently being debated at the CPUC.

Impact of High CCE Penetration on the PCIA

Currently, the PCIA calculation is based on the cost and value of a utility's portfolio, without regard to how much of that portfolio is to be paid for by bundled customers and how much by Direct Access (DA) and CCE customers. As such, the PCIA is not affected by the number of DA/CCE customers.

Currently, for bundled customers the rate impacts associated with fluctuating PCIAs are relatively small, but this will change as the number of DA/CCE customers grows. At some point, bundled customers' rates may experience marked volatility as the impacts of the annual PCIA rate swings reverberate to bundled rates. This may be unacceptable to ratepayer advocates and the Commission.

The PCIA rate volatility in part reflects changes to the utilities' generation costs, which are appropriately reflected in bundled customers' rates. But, often to a large degree, it reflects changes to the market price benchmark, which should not be relevant to bundled customer rates. For example, for a utility with flat RPS costs, a reduction to the market price benchmark for renewable power would increase the RPS-related PCIA, which would reduce bundled rates, even though there was no change in RPS costs. This could also happen in the reverse direction, increasing bundled rates when there is no increase in underlying generation costs.

Once DA/CCE load gets large enough that there are real stranded contracts, we suspect that the Commission is going to look much more closely at the value of these stranded contracts (and how to get the most value for them).

Impact of High CCE Penetration on Low-Carbon (Hydro) Resources

Virtually all the CCEs forming in California include carbon reduction as a goal. As the analysis has shown, CCEs will likely need to purchase both RPS-eligible power and other carbon-free power to meet their goals, namely large hydropower. This has been the approach used by MCE, Peninsula Clean Power, and Silicon Valley Clean Power, who all beat PG&E's GHG emissions rate through contracts for hydropower. This increased demand for carbon-free hydropower can change the "supply-demand" balance and in theory increase the cost of these resources. However, to put this in perspective, the amount of hydropower assumed in the technical study is very modest compared to its availability. For example, in the Pacific Northwest, hydroelectric facilities generated approximately 128,000 GWh of electricity, and over the past 5 (drought) years, California hydroelectric resources generated 25,000 GWhs of electricity. In contrast, the technical study assumed only 0.4-1.5 GWh/year of hydropower—well under one percent of the available resource. Furthermore, the assumed hydro premium, $10/MWh over standard market power, is much higher than the current $1.50-$2.50/MWh premiums being seen. Thus, a certain amount of market tightening is already built into the study.

Nonetheless, to address this risk, the Contra Costa County CCE should consider locking in longer-term contracts for non-RPS eligible resources early in the process so as to guarantee their availability at a reasonable price in the longer term when there could be greater demand for them.

Bonding Risk

Pursuant to CPUC Decision 05-12-041, a new CCE must include in its registration packet evidence of insurance or bond that will cover such costs as potential re-entry fees, specifically, the cost to PG&E if the CCE were to suddenly fail and be forced to return all its customers back to PG&E bundled service. Currently, a bond amount for CCEs is set at $100,000.

This $100,000 is an interim amount. In 2009, a Settlement was reached in CPUC Docket 03-10-003 between the three major California electric utilities (including PG&E), two potential CCEs (San Joaquin Valley Power Authority and the City of Victorville), and The Utility Reform Network (TURN) concerning how a bonding amount would be calculated. The settlement was vigorously opposed by MCE and San Francisco and never adopted.

Since then, the issue of CCE bond requirements has not been revisited by the CPUC.[60] If it is, the bonding requirement will likely follow that set for Energy Service Providers (ESPs) serving direct access customers. This ESP bond amount covers PG&E's administrative cost to reintegrate a failed ESP's customers back into bundled service, plus any positive difference between market-based costs for PG&E to serve the unexpected load and PG&E's retail generation rates. Because the ESP bonding requirement has been in place, retail rates have always exceeded wholesale market prices, and thus the ESP's bond requirement has been simply equal to a modest administrative cost.

If the ESP bond protocol is adopted for CCEs, during normal conditions, the CCE Bond amount will not be a concern. However, during a wholesale market price spike, the bond amount could potentially increase to millions of dollars. But the high bond amount would likely be only short term, until more stable market conditions prevailed. Also, it is important to note that high power prices (that would cause a high bond requirement) would also depress PG&E's exit fee and would also raise PG&E rates, which would in turn likely provide the CCE sufficient headroom to handle the higher bonding requirement and keep its customers' overall costs competitive with what they would have paid had they remained with PG&E. As discussed above, JPA member entities would not be individually liable for any increase in the bond amount.

[60] On January 30, 2017 the CPUC set a pre-hearing Conference to begin a process to address CCE bonding requirements.

Chapter 7: Comparative Analysis of CCE Options

Having the County and cities within the County form their own JPA and CCE Program is not the only possibility for CCE participation. First, the Counties and/or its cities may join Marin Clean Energy (MCE). In fact, 5 cities in the County—El Cerrito, Lafayette, Richmond, San Pablo, Walnut Creek—are already members of MCE. These cities joined between 2013 and 2016, and have full standing on MCE's Board of Directors. Second, the County and/or its cities could join the East Bay Community Energy (Alameda County) CCE. While this CCE has just been formed, with its JPA board having been seated in January 2017, it aims to begin power delivery in late 2017. Furthermore, the County and each city need not joint one or the other CCE *en masse*, but instead can join one or the other CCEs individually (or neither).

This chapter presents the benefits and drawbacks of joining either MCE or EBCE, forming a new CCE with the County and the cities not currently in MCE (which has been the focus of most of the analysis in this report), or remaining with PG&E. To the extent possible, this chapter considers the rate-competitiveness, GHG reduction, local economic development, local control and governance, cost risks, and CCE formation timing of each option. Some of the benefits may depend upon how much of the County chooses which path. Each community chooses for itself; thus, it is possible to have some join MCE, some join EBCE, and others remain on PG&E service. To the extent that it matters, this will be highlighted in the sections that follow.

Note that MRW & Associates are not attorneys, and that the MCE and EBCE JPA agreements are legal documents. Therefore, nothing herein should be interpreted as a legal opinion – only an informed lay-reading of the documents. MRW would strongly recommend that Contra Costa County and any city considering becoming a member of MCE or EBCE have its counsel conduct a thorough review of the respective JPA and related documents prior to committing to a CCE.

Table 25 below summarizes our results. While it is desirable to quantify some (or all) of the criteria, to do so would be an exercise in false precision. First and foremost, two of the potential CCE options are with entities which, while potentially viable, do not exist. Without power contracts, portfolios, or procurement guidelines and policies, it would be unwise to claim that EBCE or a potential Contra Costa-only CCE would have rates or greenhouse gas emissions higher or lower than the other. Comparisons against MCE can be somewhat more reasonably asserted; however, its stated goals—greater renewable energy content, lower greenhouse gas emissions, local generation, and comparable rates—are nearly identical to those stated by EBCE, so as to make long-range rate and emissions distinctions immaterial. This contrasts with PG&E, whose power portfolios, procurement plans, and costs are readily available through various filings and applications it has made before the CPUC. Thus, the qualitative comparisons provided in the table do not provide sharp distinctions between the CCE options. All these options are expected to provide similar rates and GHG emissions, with differences arising from variations in the priorities and procurement decisions of the individual governance boards. What truly distinguishes these options are primarily governance options (i.e., in-county only versus shared with other entities) and the amount of risk assumed (i.e., developing or signing on with a new CCE versus joining one with a record of satisfactory performance).

Each of the lines on the table are discussed in greater detail in the sections that follow.

Table 25. Comparison of Contra Costa CCE Options

Criterion	Form CCCo JPA	Join MCE	Join EBCE	Stay with PG&E
Rates	Likely lower	Likely Lower	Likely Lower	Base
GHG Reduction Potential Over Forecast Period	Some	Some	Some	Base
Local Control/Governance	Most	Some	Some	None
Local Economic Benefit Potential	Greatest	Some	Some	Minimal
Start Up Costs/Cost to Join	Low, but greater risk[61]	None[62]	None[62]	None
Level of Effort	Greatest	Minimal	Greater	None
Program Risks	Greatest	Minimal	Some	Base
Timing (earliest)	Late-2018	Late-2017	Mid-2018	N/A

Rates

In general, any of the three CCE options can result, in the long run, with rates that are at or slightly below those of PG&E. This is not to say that in some years PG&E's rates may be lower, or that one CCE option would consistently have rates that are lower than the others. Rather, given that a CCE's rates are a function if its communities' values—amount of local renewable generation, promotion of energy efficiency or distributed generation, overall rate minimization—and that two of the three CCEs being compared do not yet exist, let alone have rate or procurement policies, MRW cannot assert that one CCE option will have lower rates than the other two. Both MCE and EBCE have commitments to higher-cost local renewable development, which suggests that they are willing to trade off somewhat lower rates for other benefits. A

[61] Start-up costs provided by the County or others are likely to be reimbursed by the JPA.
[62] Costs already spent for consulting/technical study will likely not be reimbursed.

Contra Costa CCE that focuses more on rate reduction could in principle offer marginally lower rates than the other two.

GHG Reduction

For climate action planning and reporting purposes, the amount of GHG reduction that can be attributed to a CCE formation is a function of the difference between the average GHG emissions from PG&E and that of the CCE. PG&E's power portfolio is already relatively "clean," with large fractions coming from not only qualifying renewables but also nuclear power (through 2024) and large hydroelectric generators. As Table 26 shows, 59% of PG&E's 2015 power came from GHG-free resources. This number would be closer to 67% GHG-free but for the poor hydroelectric generation due to the ongoing drought.[63] Therefore, for any CCE to have a reduced average carbon footprint requires not only the same or greater amount of qualifying renewable generation, but additional sources of GHG-free generation.

Table 26. PG&E and MCE Power Content (2015)

	PG&E 2015	MCE 2015
Eligible renewable	30%	56%
Large Hydro	6%	12%
Nuclear	23%	0%
GHG-Free subtotal	**59%**	**68%**
Unspecified/Market	17%	25%
Natural Gas	25%	12%
Fossil subtotal	**41%**	**32%**

An approach taken by some of the currently operating Northern California CCEs is to (a) use more qualifying renewable generation than PG&E, and (b) contract with and use power from large hydroelectric resources. This is shown in MCE's power content mix, and to the extent possible, what was modeled here for Contra Costa County and for MRW's study of an Alameda County CCE.

Given that both MCE and EBCE have made GHG reductions a very high priority, one can reasonably assume that either will have some GHG-emissions benefit relative to PG&E, but there is no concrete rationale to assume that either MCE or EBCE will have a significantly-lower GHG emissions rate than the other.

Local Economic Benefits

As noted earlier in the report, the amount of local economic benefits is a function of rate reduction and local construction and CCE staffing. The number of local renewable energy projects will be a function of at least two factors. The first is any cost competitiveness advantage of renewable resources in the County; i.e., others will want to build renewable generation in the County because of cost advantages (including interconnection ease). Second, local generation

[63] However given climate change, one can sensibly argue that the lower-than-historic-average hydroelectric output in California seen over the past few years may be more predictive than the historical average.

development will be fostered by a preference for local generation by the CCE serving Contra Costa County. While all three CCE options have expressed a preference for "local" renewables, the extent to which these three programs might develop local renewable generation facilities within the County remains uncertain. MCE has already invested in Contra Costa County, with a new utility-scale solar project in Richmond and numerous individuals taking advantage of its rooftop solar program. Nonetheless, in the long run MRW would expect that a Contra Costa CCE would have the greatest interest in developing in-county renewables and thus could potentially have the greatest positive economic impact. Teaming with either of the other CCEs would dilute the interest, as the CCE would have to consider economic development in its non-Contra Costa communities as well. Given the particularly strong interest of the EBCE group in local renewables, the notion that "local" might encompass the whole "East Bay," and the fact that Contra Costa cities might have greater say in the formation of generation polities with a new group like EBCE than a more established one like MCE all suggest that EBCE might be more responsive in developing in-county renewables than MCE. On the other hand, MCE has a commanding head start, having already developed renewable projects in the County.

Contra Costa County makes up but a small fraction of PG&E's service area. While PG&E's local community engagement is admirable, it cannot focus on the County in a way that a smaller CCE can. As such, any of the three CCE scenarios will likely result in greater local economic benefits than remaining with PG&E.

CCE Governance: Voting

How each community is represented on a CCE's governing board (generally a board of directors) is laid out in its JPA agreement. Per its current JPA agreement, EBCE will have a two-stage vote: under most circumstances, each board member (each representing a single entity) would have one vote, regardless of his or her entity's size. That is, both Oakland and Piedmont would have an equal vote. In the event of a non-unanimous affirmative vote, three cities can call for a weighted vote. In that case, each Representative Board Member's vote would be weighted according to the size (in kilowatt-hours) of the entity being represented. These two voting shares are shown in Table 27.

As noted in Table 28 if EBCE consisted of Alameda County alone, the combination of the three largest entities (Oakland, Fremont, plus Hayward or Berkeley) could carry the weighted vote. If all of Contra Costa County joined EBCE, then it would take the five largest entities (Oakland, Fremont, Hayward, Unincorporated Contra Costa County plus Berkeley or Concord) to carry the vote.

Table 27. EBCE Voting Shares, With and Without Contra Costa[64]

	Simple Voting		Load-Weighted Voting*	
	Alameda Only	Alameda + Contra Costa	Alameda Only	Alameda + Contra Costa
Oakland	8.3%	3.7%	24.8%	17.5%
Fremont	8.3%	3.7%	16.2%	11.4%
Hayward	8.3%	3.7%	10.1%	7.1%
Berkeley	8.3%	3.7%	8.5%	6.0%
San Leandro	8.3%	3.7%	6.4%	4.5%
Livermore	8.3%	3.7%	6.2%	4.4%
Unincorporated Ala.	8.3%	3.7%	6.4%	4.5%
Other Alameda Cities	41.7%	18.5%	14.9%	8.3%
Alameda Total	***100.0%***	***44.4%***	***100.0%***	***63.6%***
Unincorporated C.C.		3.7%		9.0%
Concord		3.7%		5.1%
Pittsburg		3.7%		4.6%
Antioch		3.7%		3.7%
San Ramon		3.7%		3.2%
Brentwood		3.7%		2.1%
Danville		3.7%		1.7%
Martinez		3.7%		1.4%
Pleasant Hill		3.7%		1.4%
Oakley		3.7%		1.1%
Orinda		3.7%		1.0%
Hercules		3.7%		0.7%
Pinole		3.7%		0.6%
Moraga		3.7%		0.5%
Clayton		3.7%		0.3%
Contra Costa Total	***N/A***	***55.6%***	***N/A***	***36.4%***
****Only in cases where called upon by 3 Board Members***				

Table 28. EBCE Minimum Cities Needed to Carry Weighted Vote

Alameda Only	**3 cities**	**Oakland, Fremont + Hayward or Berkeley**
Alameda + Contra Costa	5 cities	Oakland, Fremont, Hayward, Unincorporated Contra Costa Co. + Berkeley or Concord

[64] It should be noted that two cities in Alameda County opted to not join the CCE at this time. Should they join, that could change the voting shares. Similarly, if not all Contra Costa jurisdictions join either MCE or EBCE, the voting shares will be different.

MCE's voting structure differs from EBCE's in two important ways. First, each board member's vote is a weighted. Half of each board member's weighting is equal to his or her entity's share of MCE's total load. The other half is an equal share for each entity. Thus, if a community is one of 26 members representing 18% of MCE's load, the board member's vote would be 10.9% (18%x(1/2) + (1/26)x(1/2)= 9% + 1.9% = 9.9%) Second, multiple entities have the option to be represented by a single board member. For example, Napa County and all the towns/cities within the County are represented by a single board member. This consolidated seat allows for potentially less administrative burden on the represented entities and "streamlines communication and policy setting." On the other hand, it effectively requires the communities with a joint board member to vote as a bloc, and while the bloc maintains the same voting share, it can reduce the "voice" of the communities: one person to speak on their behalf rather than, say, five, or six (or more).

Table 29 shows what the voting shares might be if all the Contra Costa communities joined MCE and each claimed its own board member. Together, the Contra Costa communities (including those already in MCE) would represent 71% of MCE's load and have a total 62% of the voting share.

Table 29. MCE Voting Shares With Each Contra Costa Community Having Its Own Board Member

VOTING SHARES	Entity Share	Load Share	Voting Share
Antioch	1.3%	2.8%	4.1%
Brentwood	1.3%	1.6%	2.9%
Clayton	1.3%	0.3%	1.5%
Concord	1.3%	3.9%	5.2%
Danville	1.3%	1.3%	2.6%
Hercules	1.3%	0.6%	1.8%
Martinez	1.3%	1.1%	2.4%
Moraga	1.3%	0.4%	1.6%
Oakley	1.3%	0.8%	2.1%
Orinda	1.3%	0.8%	2.0%
Pinole	1.3%	0.5%	1.7%
Pittsburg	1.3%	3.5%	4.7%
Pleasant Hill	1.3%	1.0%	2.3%
San Ramon	1.3%	2.4%	3.7%
Unincorporated Contra Costa County	1.3%	6.8%	8.1%
New Contra Costa Members	**19.2%**	**27.6%**	**46.8%**
Existing MCE Contra Costa Members	**6.4%**	**8.0%**	**14.4%**
TOTAL CONTRA COSTA COUNTY	**25.6%**	**35.6%**	**61.2%**
Rest of MCE	**24.4%**	**14.4%**	**38.8%**

CCE Governance: Other

The proposed EBCE JPA Agreement also calls for a formal Community Advisory Committee (Section 4.9). The relevant section states that the purpose of the Committee:

> "shall be to advise the Board of Directors on all subjects related to the operation of the CCA Program … with the exception of personnel and litigation decisions. The Community Advisory Committee is advisory only, and shall not have decision-making authority… The Board shall appoint members of the Community Advisory Committee from those individuals expressing interest in serving, and who represent a diverse cross-section of interests, skill sets and geographic regions."

The Chair of the Community Advisory Committee will serve as a non-voting *ex officio* member of the EBCE Board of Directors.

MCE has no analogous official community advisory committee originating from its JPA agreement. Nonetheless, there is a "Community Power Coalition" that provides input to MCE (*see*, https://www.mcecleanenergy.org/community-power-coalition/). The Coalition works "on a variety of issues ranging from local renewable energy project development – like MCE Solar One in Richmond – to outreach for MCE's Spanish-speaking constituents, to environmental justice and consumer protection issues affecting MCE's low-income customers."

The recitals to EBCE's JPA agreement lay out what can be described as its envisioned values. Besides offering competitive rates and lowering greenhouse gasses, this includes (Recitals, Section 6):

- Establishing an energy portfolio that prioritizes the use and development of local renewable resources and minimizes the use of unbundled renewable energy credits;
- Promoting an energy portfolio that incorporates energy efficiency and demand response programs and has aggressive reduced consumption goals;
- Demonstrating quantifiable economic benefits to the region (e.g. union and prevailing wage jobs, local workforce development, new energy programs, and increased local energy investments);
- Recognize the value of workers in existing jobs that support the energy infrastructure of Alameda County and Northern California. The Authority, as a leader in the shift to a clean energy, commits to ensuring it will take steps to minimize any adverse impacts to these workers to ensure a "just transition" to the new clean energy economy;
- Delivering clean energy programs and projects using a stable, skilled workforce through such mechanisms as project labor agreements, or other workforce programs that are cost effective, designed to avoid work stoppages, and ensure quality;
- Promoting personal and community ownership of renewable resources, spurring equitable economic development and increased resilience, especially in low income communities;
- Provide and manage lower cost energy supplies in a manner that provides cost savings to low-income households and promotes public health in areas impacted by energy production; and

- Create an administering agency that is financially sustainable, responsive to regional priorities, well managed, and a leader in fair and equitable treatment of employees through adopting appropriate best practices employment policies, including, but not limited to, promoting efficient consideration of petitions to unionize, and providing appropriate wages and benefits.

Contra Costa communities considering joining EBCE should consider these enunciated values prior to committing to membership.

Timing and Process to Join/Form

The timing required to serve Contra Costa businesses and residents vary markedly among the CCE options. The quickest path the CCE service would be to join with MCE. The first step for a community to join MCE is for its governing body or representative (e.g., city manager) to provide MCE a non-binding letter of interest. The entity's governing body would then need to adopt a resolution requesting MCE membership; have a first reading of an ordinance to join MCE; execute a memorandum of understanding between the entity and MCE to address preliminary data and communication issues; and provide a signed request for PG&E to provide MCE its load data. These steps would need to occur during MCE's "inclusion period" which currently runs from December 1, 2016 through May 31, 2017. Only communities in Contra Costa County are eligible to request MCE membership during this period.

MCE would then evaluate the impact of the new load on its system. If the net result of adding the new community is that MCE's rates would increase, then that community's membership would be tabled until a future date. If the MCE analysis shows that adding the community is favorable, then the MCE Board would vote to accept (or not) the community into MCE. At that point, the local ordinance for MCE membership would receive a second reading and adoption. MCE would them modify its official Implementation Plan to reflect the new community, and submit the updated plan to the California Public Utilities Commission. Once approved (none have been rejected), the phase-in of the community into MCE can occur.

Based on MCE's currently Inclusion Period, Contra Costa County and the jurisdictions not already served by MCE could begin MCE service as early as late 2017.

Although it has just recently formed, the EBCE board has extended an offer to interested Contra Costa communities to join EBCE. In a letter from Chris Bazar, Director, Alameda County Community Development Agency, EBCE would welcome Contra Costa members into its Phase 2 or Phase 3 rollout.[65]

The current EBCE JPA documents states in Section 3.1, Addition of Parties:

> Subject to Section 2.2, relating to certain rights of Initial Participants, other incorporated municipalities and counties may become Parties upon (a) the adoption of a resolution by the governing body of such incorporated municipality or county requesting that the incorporated municipality or county, as the case may be, become a member of the

[65] The letter suggests that Phase 2 would commence in the summer of 2018 and Phase 3 in Fall 2018 or Spring 2019.

> Authority, (b) the adoption by an affirmative vote of a majority of all Directors of the entire Board satisfying the requirements described in Section 4.12, of a resolution authorizing membership of the additional incorporated municipality or county, specifying the membership payment, if any, to be made by the additional incorporated municipality or county to reflect its pro rata share of organizational, planning and other pre-existing expenditures, and describing additional conditions, if any, associated with membership, (c) the adoption of an ordinance required by Public Utilities Code Section 366.2(c)(12) and execution of this Agreement and other necessary program agreements by the incorporated municipality or county, (d) payment of the membership fee, if any, and (e) satisfaction of any conditions established by the Board..

Thus, a Contra Costa community would need to adopt a resolution requesting membership in the EBCE, the board of Directors of EBCE would have to vote to authorize the applying community's membership, followed by the applying entity passing an ordinance to join. To be part of the Phase 2 rollout, a City would have need to have an ordinance passed by June 30, 2017.

Implementing a Contra Costa County only CCE would likely have a time line similar to joining EBCE. If the County and its cities were committed to this path, it could potentially begin service as early as 2018. This is consistent with Peninsula Clean Energy, which went from putting out an RFP for a technical study to Phase 1 implementation in 18 months (April 2, 2015 to October 1, 2016). A more measured timeline would suggest that a new Contra Costa CCE would spend much of 2017, planning and generating local support, with implementation beginning in late 2018 or 2019.

Costs to Join the CCE

This section discusses direct, non-reimbursable costs to cities for joining either EBCE or MCE. So far, cities joining MCE have not had to pay for any of the costs incurred by MCE to plan for or integrate their load. They have often spent on the order of $10,000 to $15,000 for consultants to evaluate the risks to the city and its residents and businesses that could come from joining MCE. Both MCE and EBCE have extended a no-cost opportunity to join to the Contra Costa jurisdictions who are not already members of MCE.

The start-up costs for a new Contra Costa CCE would be significant—Alameda County has committed $3.4 million to its effort. However, consistent with other CCEs, these costs would be initially reimbursed to the County and funding cities by a loan taken out by the CCE's JPA, which would in turn be paid down via CCE rates over the initial few years. As such, the only "cost to join" a Contra Costa CCE felt by any individual city would be indirect at best (i.e., asked to backstop any CCE loads with the entities' credit).

Exiting the CCE

MCE's JPA Section 7.0 lays out the process and ramifications of a MEC member withdrawing from the JPA. First, an entity may withdraw from the JPA within 30 days of its notification of joining the JPA, assuming that MCE has not entered into any wholesale power agreements to serve the entity. (Section 7.1.1.1) After MCE has entered into wholesale power agreements to serve the entity, the entity may withdraw from MCE, effective the beginning of the JPA's fiscal year by giving at least 6 months' written notice of its intent to withdraw. The withdrawing entity may be subject to "certain continuing liabilities" as laid out in Section 7.3:

> **<u>7.3 Continuing Liability; Refund</u>**. Upon a withdrawal or involuntary termination of a Party, the Party shall remain responsible for any claims, demands, damages, or liabilities arising from the Party's membership in the Authority through the date of its withdrawal or involuntary termination, it being agreed that the Party shall not be responsible for any claims, demands, damages, or liabilities arising after the date of the Party's withdrawal or involuntary termination. In addition, such Party also shall be responsible for any costs or obligations associated with the Party's participation in any program in accordance with the provisions of any agreements relating to such program provided such costs or obligations were incurred prior to the withdrawal of the Party. The Authority may withhold funds otherwise owing to the Party or may require the Party to deposit sufficient funds with the Authority, as reasonably determined by the Authority, to cover the Party's liability for the costs described above. Any amount of the Party's funds held on deposit with the Authority above that which is required to pay any liabilities or obligations shall be returned to the Party.

Neither the precise calculation of the liabilities nor now it would be collected is specified.

The proposed EBCE JPA Agreement contains no language concerning a community's exit from EBCE or the JPA.

Remaining With PG&E

Although this study suggests CCE program options would likely produce both environmental and economic benefits for the jurisdictions included in the study, continuing service with PG&E remains an option for not only a community but also for any individual or business whose community has selected CCE service (i.e., each individual account maintains its right to opt-out of CCE service). There are benefits of remaining with PG&E, even at a community level. First, remaining with PG&E takes no city action. Thus, a city's leadership and staff can concentrate their limited resources on matters that may be more pressing. Second, PG&E is regulated by the State via the California Public Utilities Commission (CPUC), which oversees its power procurement and approves its rates. While CCEs are partially regulated by the CPUC (e.g., ensuring that the CCE complies with any applicable laws), they are not subject to rate regulation. Some may see State oversight as a benefit, with an official "watchdog" overseeing power supply and procurement, while others might see the local CCE board accountability as a benefit. Third, PG&E is much larger than any of the CCE options that Contra Costa communities might pursue, which (as discussed) might reduce community input and value but also provide some economies of scale. For example, one poor power contract entered might have significant rate or operational ramifications for a CCE. For PG&E, given its size, the impact of that same poor contract would be diluted. Lastly, simply because a Contra Costa community does not join a CCE in 2017 or 2018 does not necessarily preclude it from doing so in the future, although waiting may result in an "entry fee" or perhaps a high PCIA rate.

Summary

The following lays out the principal benefits and risks of each of the options considered.

Potential Benefits of Forming Contra Costa CCE (relative to joining MCE or EBCE)

- More local control (voting shares not diluted)
- Can form JPA and policies to fully reflect County interests and values
- Greatest potential for local economic development (due largely to more local control)
- Even if formed, individuals may still select PG&E as their power provider

Potential Risks/Downsides of Forming Contra Costa CCE (relative to joining MCE or EBCE)

- Commitment of County and city resources to establish a new CCE agency
- Higher risks due lack of experience, fewer partners
- Would need to establish programs, contractors, credit, etc.
- Longest time line to begin enrolling customers
- Given MCE's presence in five Contra Costa communities, potential customer confusion with multiple CCEs in the same county

Potential Benefits of joining MCE (relative to joining EBCE)

- Five other Contra Costa County communities have already joined
- Established, successful program
- Credit capacity and programs in place
- Likely easier transition/implementation
- Able to enroll customers sooner than EBCE
- Programs that create jobs and economic benefits could be implemented more quickly

Potential Risks/Downsides of joining MCE (relative to joining EBCE)

- May have less Board representation (if all of Contra Costa County and its jurisdictions are represented by a shared seat)
- May be less of a "fit" compared to East Bay identification and sensibilities (or, for some cities, this may be a benefit)
- Programs are already in place; less/minimal input into their formation
- Joining a large board serving a very diverse customer base and geography

Potential Benefits of joining EBCE (relative to joining MCE)

- Coming in closer to the "ground floor" — opportunity to influence policy direction and program development
- May be more mission or cultural alignment (East Bay vs. Marin) (or perhaps for some communities, not)

- Board will more likely be one seat per member jurisdiction (not a shared seat)
- Weighted voting process is a little clearer
- EBCE working on a local development business plan with emphasis on local power production in the East Bay

Potential Risks/Downsides of joining EBCE (relative to joining MCE)

- Take longer to enroll County communities
- Take longer for job-creating programs to get up and running
- May be a small fish among some very large fish (Oakland, Hayward)
- Union focused policies may be difficult for some (or preferable)
- Given MCE's presence in five Contra Costa communities, potential customer confusion with multiple CCEs in the same county

Potential Benefits of Remaining with PG&E (relative to joining or forming a CCE)

- Experienced provider
- State regulatory protection
- Continuity- same firm provides all services
- No action needed by City/County—status quo
- May be able to join a CCE at a later date (but perhaps at some cost)

Potential Risks/Downsides Benefits of Remaining with PG&E (relative to joining or forming a CCE)

- Higher GHG emissions
- Less local renewable generation
- Higher electricity rates than CCE rates under most scenarios
- Less local control
- Less local input into policies and offerings
- Less local economic development

Chapter 8: Other Issues Investigated

Synergies on the Northern Waterfront

Contra Costa County has an ongoing initiative to economically develop its Northern Waterfront. The Northern Waterfront stretches from the City of Hercules at San Pablo Bay, along the southern shore of the Carquinez Straight and Suisun Bay, and out to the San Joaquin Delta region of Oakley. The County's Northern Waterfront Economic Development Initiative is a regional cluster-based economic development strategy with a goal of creating 18,000 new jobs by 2035. The Initiative leverages existing competitive advantages and assets by focusing on advanced manufacturing sub-sectors in five targeted clusters (advanced transportation fuels, bio-tech/bio medical, diverse manufacturing, food processing, and clean tech).

To assess the potential positive impacts a CCE might have on this Area, the study looked at the Northern Waterfront to assess local generation potential within the area. Of the potential 3,350 MW of solar resources in the County, approximately 40% lies within the Northern Waterfront. As shown in Table 30, there are over 700 potential solar sites in the area, which could theoretically generate over 2,000 GWhs. Of these sites, over 800 MW have the highest potential ranking, meaning that they are the most appropriate for actual development. In fact, all the local solar capacity specified in Scenarios 3 or 4 could be met at sites in the Northern Waterfront alone.

Table 30 Solar Potential in the Northern Waterfront

Location	Solar Sites	PV Potential (MW)	PV Production (GWh)	Build Cost ($ Thousands)
Antioch	189	327	524	$747,130
Concord	108	191	306	$442,015
Crockett	21	58	93	$125,187
Hercules	52	90	144	$200,512
Martinez	139	300	480	$629,130
Oakley	43	76	121	$178,390
Pinole	17	24	39	$57,208
Pittsburg	153	298	477	$679,851
Rodeo	14	35	57	$85,875
Grand Total	**736**	**1,400**	**2,241**	**$3,145,298**

How much solar could actually be sited in the Northern Waterfront would depend upon (a) the degree to which there is competition for sites for perhaps higher-value projects and (b) the CCE's policies toward fostering local projects.

In addition to this renewable potential, the Northern Waterfront also hosts six major power plants (Table 31). In addition to these, the refineries in the area also generate much of their own power.

A Contra Costa CCE could contract with one of more of these facilities to provide the CCE's Resource Adequacy Requirements or a portion of its energy needs. Alone, a Contra Costa CCE would not be able to use all—or even most—of the power produced by any of these or other major power plant of this magnitude (e.g., the cancelled Oakley power plant).

Table 31. Natural Gas Power Plants in the Northern Waterfront

Plant	Location	Capacity (MW)	Year in Service	Owner	Type
Crockett Cogen	Crocket	275	1995		Steam-Cogen
Los Medanos	Pittsburg	555	2001	Calpine	Combined cycle -Cogen
Delta Energy Facility	Pittsburg	887	2002	Calpine	Combined cycle
Gateway	Antioch	530	2009	PG&E	Combined cycle
March Landing	Antioch	760	2013	NRG	Combined cycle
Pittsburg	Pittsburg	1,029	1970s	NRG	Steam, combined cycle

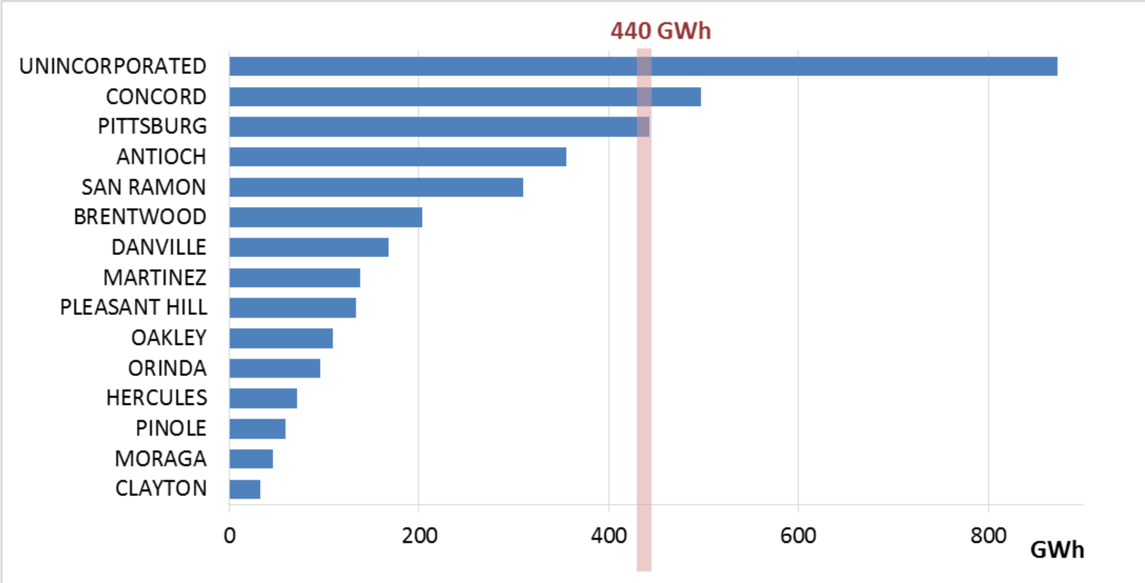
"Minimum" CCE Size?

MRW's analysis above assumed that all eligible Contra Costa County cities join the Contra Costa County CCE program with a participation rate of 85% from each city, resulting in an anticipated CCE load of about 3.6 million MWh per year.[66] If fewer customers join, CCE rates will generally be higher because about $7 million of annual CCE costs are invariant to the amount of CCE load. Along with the number of customers, the customer make-up is also important. For example, a higher share of residential customers would improve the competitiveness of the CCE, while a higher share of commercial customers or industrial customers would weaken the competitiveness of the CCE. Because cities vary in their distribution of customers by rate class, a city opting out of the CCE could affect the competitiveness of the CCE due to both the reduction in CCE load and the shift in customer make-up.

To identify the "minimum" load needed for CCE customer rates to be no higher than PG&E customer rates, we will analyze only the period between 2018 and 2030. The "minimum" load for this period is approximately 440,000 MWh per year, assuming the average customer portfolio for Contra Costa County and Supply Scenario 1. This value was estimated by assuming that the fixed costs remained the same (i.e., did not scale with sales) and then lowering the sales until the hypothetical reduced CCE's rates were equal to PG&E's. As shown in Figure 31, this is roughly the load from the big cities (Concord and Pittsburg) and is much smaller than the load from the unincorporated area. As long as two medium-sized cities or one larger city joins the CCE, this "minimum" load will be met. It is not a true minimum, however, because the true minimum depends on the make-up of the customer portfolio; for example, for the stand-alone city of Pittsburg,[67] due to its load with more industrial proportion, the CCE program would not be cost-competitive.

[66] In the alternate supply scenarios, the "minimum" annual load assuming the average customer portfolio for Contra Costa County and the base case is 550,000 MWh (Scenario 2).
[67] See Figure 2. Pittsburg is the only city with this highly industrial profile.

Figure 31. Potential load (85% participation) per city



Individuals and Communities Self-Selecting 100% Renewables

The existing CCEs all offer customers an option to choose to receive 100% of their power from renewable resources in exchange for a rate premium. However, each CCE's program is different. MCE Clean Energy has offered its "Deep Green" at a rate premium of 1¢/kWh because its inception. Sonoma Clean Power offers its "Evergreen" option at approximately the same price as PG&E's "Solar Choice" rate. Lancaster Choice Energy offers its Smart Choice as a fixed monthly premium rather than a variable rate. In all cases, only a very modest number of CCE customers—on the order of a few percent—have selected the 100% green rate option.

Table 32. CCE 100% Green Rate Premiums

CCE	Rate Option	Increment Above Default Rate
Marin Clean Energy	Deep Green	1¢/kWh
Sonoma Clean Power	EverGreen	3.5¢/kWh
Lancaster Choice Energy	Smart Choice	$10/month
Peninsula Clean Energy	ECO100	1¢/kWh
CleanPowerSF	SuperGreen	2¢/kWh
Potential Contra Costa Co. CCE	**TBD**	**~1.5¢/kWh**

Any full renewable pricing option offered by the Contra Costa County CCE would have to be set by the CCE's management. The value shown in Table 32, ~1.5¢/kWh, is the average incremental cost of green power used in the CCE supply assessment (Scenario 2) over the study period. (Initially, it would have to be ~1.9¢/kWh.) The number of customers selecting the rate would not impact the economics of the CCE customer who remain on the standard rate.

- Separate CCE opt-out notifications would be needed. A key feature of the opt-out notification is the price comparisons against PG&E. As the default rate would be different for these communities, a different notice would have to be sent. This would simply increase the start-up cost for the CCE, the increment could be paid for by the city electing a different default rate.
- Having a higher default rate might increase the number of oft-outs in the community.
- PG&E's billing system would have to be able to handle city- or zip code-specific default options. That is, as new residential or businesses move to a self-selected green community, the billing system would need to know to default them on a different rate schedule than a customer in a different CCE community. This may or may not be an issue.

Competition with a PG&E Solar Choice Program

PG&E has been offering a solar choice program known as Green Tariff Shared Renewable Program since February 2015.[68] The program was established under Senate Bill 43, and pursuant to Decision 15-01-051 from the CPUC, to extend access to renewable energy to ratepayers that are currently unable to install onsite generation.[69] It offers homes and businesses the option to purchase 50% or 100% of their energy use from solar resources. The program provides those with homes or apartments or businesses that cannot support rooftop solar the opportunity to meet their electricity requirements through renewable energy and support the growth of renewable energy resources.

PG&E's current Solar Choice program costs residential customers an additional 3.58¢/kWh. Given that MRW projects that the CCE can offer 100% green power at ~1.5¢/kWh over its own Scenario 1 or Scenario 2 rate (which is projected to be less than PG&E's), we do not believe PG&E's Community Solar Program will be price competitive with similar CCE product options.

The program is open for enrollment until subscriptions reach 272 MW or January 1, 2019, whichever comes first.[70] While this does limit the ability for PG&E to provide a 100% renewable

[68] PG&E website http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/RFO/CommunitySolarChoice.page?WT.mc_id=Vanity_communitysolarchoice. Accessed 5/16/2016

[69] California Public Utilities Commission, Decision 15-01-051, p.3

[70] Solar Choice Program FAQs website, https://www.pge.com/en/myhome/saveenergymoney/solar/choice/faq/index.page Accessed, 5/16/2016

option in the long-run, at the start of the CCE this program it provides an opportunity for customers who desire 100% renewable power to remain with PG&E.

Differences Between the Analyses for Contra Costa and Alameda Counties

In the first half of 2016, MRW prepared a similar CCE analysis for Alameda County.[71] Although the fundamental approach and results of study and this one are the same, there are several differing assumptions resulting in differing results. If we compare the results of the present study with the results obtained in the Alameda CCE study, we observe that the savings for CCE customers are very similar in both studies, though PG&E rates and CCE rates are both approximately 1¢/kWh higher in the current study than in the prior study (**Table 33**).

Table 33. Average prices for 2018-2030 Scenario 1 for Contra Costa and Alameda County CCE programs

Average Period 2018-2030	Contra Costa County	Alameda County
Price natural gas ($/MMBtu)	5.70	4.90
Wholesale ($/MWh)	51.30	44.80
PG&E Capacity ($/MWh)	74	39
CCE Capacity ($/MWh)	52	39
Wind ($/MWh)	56	57
Solar Distant ($/MWh)	51	51
Solar Local ($/MWh)	98	74
% Local Solar by 2030	25%	10%
PG&E rate (¢/kWh)	11.7	10.4
PCIA rate (¢/kWh)	1.4	1.4
CCE rate (¢/kWh)	9.4	8.3
Difference CCE-PGE (¢/kWh)	2.3	2.1

The results of the present study for Contra Costa County differ from the prior results for Alameda County because we updated our forecast to reflect new PG&E rate filings and other public forecasts. The main changes between the models are as follows:

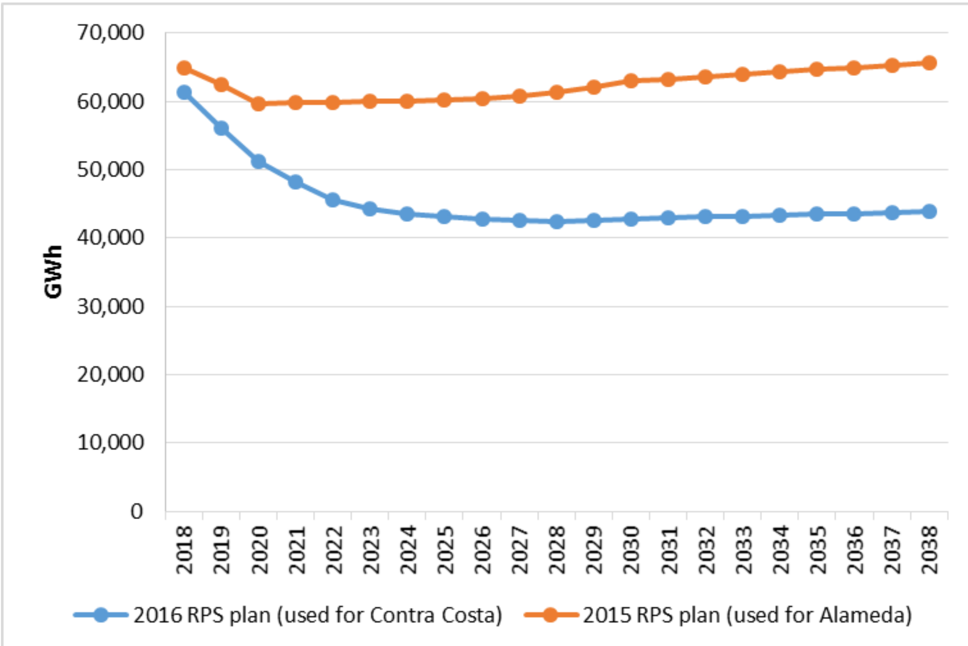
- **Bundled Load Forecast**: As a result of increased interest in CCE, PG&E's most recent bundled load forecasts are 3% below the previously available forecasts for 2017 and an average of 25% below the previously available forecasts over the 2018-2030 period (see Figure 32).[72] Less load reduces PG&E's procurement costs, increases the share of fixed costs

[71] The final version of the Alameda CCE technical study was published on July 1, 2016. https://www.acgov.org/cda/planning/cca/documents/Feas-TechAnalysisDRAFT5312016.pdf

[72] The sources for the 2017 bundled load forecasts are PG&E's 2017 preliminary and final ERRA forecasts. (The June 2016 preliminary forecast was used in the Alameda County CCE study, and the November 2016 final forecast

paid by remaining bundled customers, and increases the revenue provided to bundled customers from CCE exit fees. These effects mostly offset each other, resulting in little net change to bundled rates.[73]

Figure 32: Bundled Load Forecasts used in the Alameda and Contra Costa County Analyses



- **Natural gas prices**: Projections for natural gas prices are about $0.80/MMBtu higher than they were in the spring when the Alameda County report was developed. The higher natural gas prices increase wholesale market prices by $7/MWh (14%).
- **Diablo Canyon Retirement application**: In July 2016, PG&E, together with other entities, submitted a proposal to retire the two units of Diablo Canyon when their licenses expire in November 2024 and August 2025. Per the proposal, PG&E would replace Diablo Canyon production with energy efficiency and greenhouse gas-free generation resources. These resources would include the following: (1) 2,000 GWh of load reduction from additional energy efficiency to be installed by January 2025, (2) 2,000 GWh of load reduction or generation from GHG-free generation resources to be on-line between 2025 and 2030, and (3) a voluntary commitment from PG&E to meet a 55% RPS for 2031-2045 (instead of the 50% requirement currently in effect). The joint proposal estimated that the retirement of Diablo Canyon would result in a need for new generation capacity ("load-resource balance") around 2030, which is about five years earlier than previously anticipated.

was used in the present study.) The sources for the 2018-2030 bundled load forecasts are PG&E's RPS plans for 2015 (filed in January 2016, used for Alameda County) and for 2016 (draft filed in August 2016, used for Contra Costa).

[73] CCE exit fees are designed so that bundled customers' rates are not affected by CCE departures. In practice, some impact is likely in one direction or the other, and the magnitude and direction of this impact may each vary year by year.

The new energy efficiency resources together with other costs of the nuclear plant retirement would be recovered through non-generation rates (mostly Public Purpose Program and Nuclear Decommissioning charges), and the new RPS resources would be recovered through a new "Clean Energy Charge" applied to all PG&E retail customers. For those load serving entities that are willing to commit to procuring the equivalent new RPS resources, PG&E has proposed a "self-provision" option that would exempt existing DA and CCE loads from the Clean Energy Charge. In the analysis for Contra Costa County, MRW assumed that Contra Costa CCE would choose the "self-provision" option.

MRW assumed for this study that the Diablo Canyon retirement proposal would be adopted, though the proposal is under evaluation by the Commission and is subject to modification. Based on this proposal, we modified the PG&E and Contra Costa County CCE power supply forecasts as follows:[74]

1) PG&E's RPS requirements were increased for 2030-2038 from 50% to 55%,[75]
2) Contra Costa County CCE's RPS requirements were increased for 2030-2038 to 55% (vs. the 50% that was used in the Alameda County CCE study), and
3) We began increasing the price of capacity five years earlier than we had in the Alameda County CCE study, reflecting the earlier load-resource balance date due to the retirement of Diablo Canyon. For both Alameda and Contra Costa counties, MRW assumed that the CCEs would build their own power plants (alone or in combination with other public entities) in place of purchasing market capacity when market prices rise above the cost of a new self-build.

On February 27, 2017, PG&E withdrew portions of its Diablo Canyon retirement proposal. In particular, PG&E states it will still pursue GHG-free replacement resources, but will do so in a different CPUC proceeding. MRW does not believe that this change has a material impact on this analysis.

[74] We also accounted for the changes in the Public Purpose Program and Nuclear Decommissioning fees in our calculation of the Residential bills.
[75] The generation share of the 2025-2030 commitment for 2,000 GWh of load reduction or GHG-free generation was assumed to be subsumed by procurement needed to meet a 50% RPS by 2030 and therefore did not result in incremental renewable generation in our model.

Chapter 9: Conclusions

Overall, a CCE in Contra Costa County appears feasible. Given current and expected market and regulatory conditions, a Contra Costa County CCE should be able to offer its residents and business electric rates that are less than that available from PG&E.

Sensitivity analyses suggest that these results are relatively robust. Only when very high amounts of local renewable energy are assumed in the CCE portfolio (Scenario 4), combined with other negative factors, do PG&E's rates become consistently more favorable than the CCE's.

A Contra Costa County CCE would also be well positioned to help facilitate the installation of greater amounts renewable generation in the County. Because the CCE would have a much greater interest in developing local solar than PG&E, it is much more likely that such development would actually occur with a CCE in the County than without it.

The CCE can also reduce the amount greenhouse gases emitted by the County, but only under certain circumstances. Because PG&E's supply portfolio has significant carbon-free generation (large hydroelectric and nuclear generators), the CCE must contract for significant amounts of carbon-fee power above and beyond the required qualifying renewables in order to actually reduce the County's electric carbon footprint. Therefore, if carbon reductions are a high priority for the CCE, a concerted effort to contract with hydroelectric or other carbon-free generators would be needed.

A CCE can also offer positive economic development and employment benefits to the County. At the peak, the CCE could create approximately 500 to 700 new jobs in the County, plus an additional 200 jobs in the neighboring counties if local renewable development is prioritized.

While the analytical focus of this report has been on a stand-alone Contra Costa County CCE for those communities not already in MCE that is not the only, nor necessarily best, choice for these communities. Overall, there is insufficient data to suggest that a stand-alone Contra Costa CCE would offer lower rates or greater GHG savings that joining MCE or EBCE. Either forming or joining a CCE would likely offer modestly lower rates and more local economic development that remaining with PG&E. Joining MCE would likely result in the quickest and least risky path to CCE implementation, however with diminished local input into CCE policy formation. Because it has yet to be formed, joining with EBCE would take longer and involve more uncertainty than joining the already-established MCE, but would offer greater input into the CCE's policies and formation.

Although this study suggests CCE program options would likely produce both environmental and economic benefits for the jurisdictions included in the study, continuing service with PG&E remains an option for not only a community but also for any individual or business whose community has selected CCE service. PG&E is an experienced power provider and is regulated by the state. Furthermore, remaining with PG&E takes no city action. Lastly, simply because a Contra Costa community does not join a CCE in 2017 or 2018 does not necessarily preclude it from doing so in the future, although waiting may result in an "entry fee" or perhaps a high PCIA rate.

Technical Study for Community Choice Energy Program in Contra Costa County

Appendices

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Appendix A. Loads and Forecast

Appendix B. Power Supply Cost

Appendix C. Forecast of PG&E's Generation Rates

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Appendix H. MCE's Joint Powers Agreements

Appendix I. MCE's approval for inclusion of Contra Costa

Appendix J. EBCE's Joint Powers Agreement

Appendix K. EBCE's offer for inclusion of Contra Costa

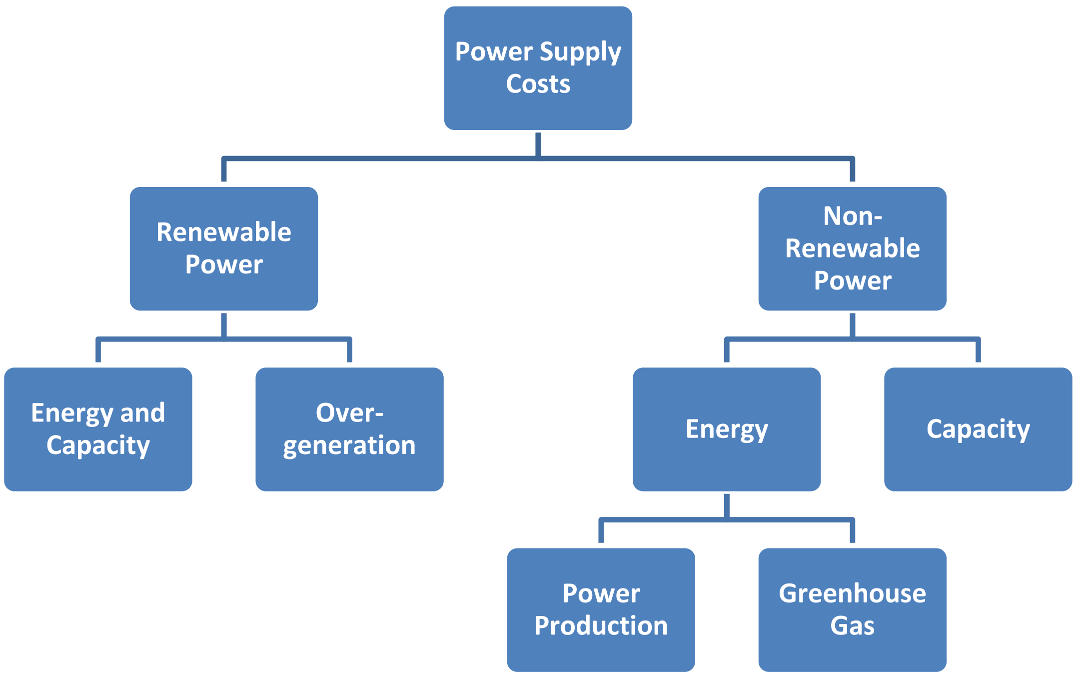
Appendix A. Loads and Forecast

2014 Load (MWh)	Residential	Commercial	Industrial	Public	Street lights + Pumping
UNINCORPORATED	454,716	252,156	237,085	63,574	19,925
CONCORD	269,024	242,584	53,969	18,228	885
PITTSBURG	145,304	134,197	225,362	14,807	1,635
ANTIOCH	270,761	109,487	18,340	18,694	1,077
SAN RAMON	172,364	140,696	32,012	14,458	4,461
BRENTWOOD	150,827	66,635	0	16,407	4,970
DANVILLE	133,085	51,478	0	11,944	1,394
MARTINEZ	86,638	61,730	6,372	6,121	1,140
PLEASANT HILL	82,411	67,087	0	5,905	1,270
OAKLEY	96,389	18,236	0	12,431	901
ORINDA	58,779	14,719	0	39,747	215
HERCULES	48,162	32,749	0	2,751	700
PINOLE	36,629	26,028	0	5,877	963
MORAGA	40,593	8,818	0	3,701	456
CLAYTON	31,795	4,759	0	1,808	661
TOTAL	**2,077,476**	**1,231,360**	**573,139**	**236,454**	**40,652**

Appendix B. Power Supply Cost

MRW has developed a bottoms-up calculation of Contra Costa County CCA's power supply costs, separately forecasting the cost of each power supply element. These elements are renewable energy, non-renewable energy (including power production costs and greenhouse gas costs), resource adequacy (RA) capacity (both renewable and non-renewable supplies) and related costs (e.g., CAISO expenses and broker fees).[1] Figure 1 illustrates the components of Contra Costa County CCA's expected supply costs.

Figure 1: Power Supply Cost Forecast



Renewable Power Cost Forecast

MRW developed a forecast of renewable generation prices starting from an assessment of the current market price for renewable power. For the current market price, MRW relied on wind and solar contract prices reported by California municipal utilities and Community Choice Aggregation (CCA) entities in 2015 and early 2016, finding an average price of $52 per MWh for these contracts.[2]

[1] MRW included a 5.5% adder in the power supply cost for CAISO costs (ancillary services, etc.), and a 5% premium for contracted supplies to reflect broker fees and similar expenses.

[2] MRW relied exclusively on prices from municipal utilities and CCAs because investor-owned utility contract prices from this period are not yet public. We included all reported wind and solar power purchase agreements, excluding local builds (which generally come at a price premium), as reported in California Energy Markets, an

To forecast the future price of renewable purchases, MRW considered a number of factors:

- Researchers from the National Renewable Energy Laboratory (NREL) and Lawrence Berkeley National Laboratory (LBNL) developed a set of forecasts of utility-scale solar costs based on market data and preliminary data from other research efforts.[3] Their base case forecast predicts a 3.8% annual decline in utility-scale solar capital costs on a nominal basis, from $1,932/kW-DC in 2016 to $1,652/kW-DC in 2020, with costs then remaining roughly constant in nominal dollars through 2030.[4] Additional scenarios predict even steeper price declines, with the most aggressive scenario predicting an 11% annual nominal decline through 2020, with increases at the rate of inflation after that.
- The federal Investment Tax Credit (ITC), which is commonly used by solar developers, is scheduled to remain at its current level of 30% through 2019 and then to fall over three years to 10%, where it is to remain.[5] The federal Production Tax Credit, which is commonly used by wind developers, is scheduled to be reduced for facilities commencing construction in 2017-2019 and eliminated for subsequent construction.[6] The loss of these credits would put upward pressure on prices.
- NREL and LBNL researchers predicted in 2015 that the cost increase associated with an ITC reduction would be roughly offset by other solar cost reductions even if the full reduction to 10% were to be implemented by 2018, rather than spread out through 2022 as is currently planned.[7]
- Lawrence Berkeley National Laboratory researchers conducted a study anticipating a reduction of the wind costs of 24% by 2030 and 35% by 2050.[8]

independent news service from Energy Newsdata, from January 2015-January 2016 (see issues dated July 31, August 14, October 16, October 30, 2015, and January 15, 2016).

[3] National Renewable Energy Laboratory. Impact of Federal Tax Policy on Utility-Scale Solar Deployment Given Financing Interactions, September 28, 2015, Slide 16. http://www.nrel.gov/docs/fy16osti/65014.pdf

[4] Ibid. Costs converted to nominal dollars using the inflation forecast used throughout the rate forecast model (U.S. EIA's forecast of the Gross Domestic Product Implicit Price Deflator).

[5] U.S. Department of Energy. Business Energy Investment Tax Credit (ITC). http://energy.gov/savings/business-energy-investment-tax-credit-itc

[6] U.S. Department of Energy. Electricity Production Tax Credit (PTC). http://energy.gov/savings/renewable-electricity-production-tax-credit-ptc

[7] National Renewable Energy Laboratory. Impact of Federal Tax Policy on Utility-Scale Solar Deployment Given Financing Interactions, September 28, 2015, Slide 28.

[8] Lawrence Berkeley National Laboratory . Expert elicitation survey on future wind and energy costs. Nature Energy, September 12th, 2016.

- The production tax credit has been extended six times from 2000-2014,[9] and the solar ITC has been extended three times since 2007.[10] Further tax credit extensions are therefore plausible.
- The major California investor-owned utilities have significantly slowed their renewable procurement because lower-than-expected customer sales and higher-than-expected contracting success rates have led to procurement in excess of the RPS requirements through 2020. When the utilities start ramping their procurement back up to meet the 50%-by-2030 RPS requirement, the supply-demand balance in the market may shift, resulting in higher-than-expected prices unless an increase in suppliers and development opportunities matches the increase in demand.

Given the potential upward price pressures from tax credits that are currently expected to expire and from higher demand for renewable power to meet the 50%-by-2030 requirement and the potential downward price pressures from falling renewable development costs, the possibility for lower cost procurement through the use of RECs, and the possibility that the expiry of the tax credits will be further delayed, it is unclear whether renewable prices will continue to fall (as NREL, LBNL, and others are predicting) or will start to stabilize and rise.

MRW has addressed this uncertainty by considering two scenarios for this sensitivity case:

- In the solar base renewable cost forecast, MRW used the $48.5 per MWh average price of recent municipal utility and CCA solar contracts as the price through 2022 (in nominal dollars), which will increase with inflation in subsequent years. This results in a solar price of $57 per MWh in 2030, and of $67 per MWh in 2038. In the wind base renewable cost forecast, MRW used the $55.0 per MWh average price of recent municipal utility and CCA solar contracts as starting point, and extended it applying an annual decrease of 2% through 2030 and 1% through 2038, offset by inflation. This results in a wind price of $57 per MWh in 2030, and of $62 per MWh in 2038.
- In the high renewable cost scenario, MRW increased both wind and solar base case prices to account for the expected expiration of the tax credits, resulting in average a price of $75 per MWh in 2030 and $86 per MWh in 2038. These scenarios provide a reasonable window of renewable price projections based on current market conditions and analysts' expectations.

MRW used these same renewable prices to calculate PG&E's renewable power costs. However, as described in Appendix B in the PG&E forecast, these renewable energy prices are used only

[9] Union of Concerned Scientists. Production Tax Credit for Renewable Energy. http://www.ucsusa.org/clean_energy/smart-energy-solutions/increase-renewables/production-tax-credit-for.html

[10] Solar Energy Industries Association. Solar Investment Tax Credit. http://www.seia.org/policy/finance-tax/solar-investment-tax-credit; and U.S. Department of Energy. Business Energy Investment Tax Credit (ITC). http://energy.gov/savings/business-energy-investment-tax-credit-itc

for incremental power that is needed above PG&E's existing RPS contracts. For Contra Costa County CCA, these prices are used as the basis for its entire RPS-eligible portfolio.

MRW additionally included a premium for the portion of Contra Costa County CCA's RPS portfolio assumed in each scenario to be located in Contra Costa County County. While solar energy is anticipated to provide the largest share of incremental supply located in-county, the solar resource in Contra Costa County is not as strong as in the areas being developed to supply the contracts discussed above. As a result, the cost of solar generation in Contra Costa County is expected to be higher than the assumed contract prices for non- Contra Costa County supplies. Based on information provided in the CPUC's current RPS calculator, combined with SAGE inputs (performance assumptions and capital cost of the projects[11]), the current cost for solar generation in Contra Costa County is expected to be approximately $98 per MWh. In addition, it is assumed the local solar generation cost will scale with installed capacity.

Non-Renewable Energy Cost Forecast

MRW separated the costs of non-renewable energy generation into two components: power production costs and greenhouse gas costs. The forecast methodologies for these cost elements, described below, are consistent with the forecast methodologies used for these cost elements in the PG&E rate forecast.

Since natural gas generation is typically on the margin in the California wholesale power market, power production costs for market power are driven by the price for natural gas. MRW forecasted natural gas prices based on current NYMEX market futures prices for natural gas, projected long-term natural gas prices in the EIA's *2016 Annual Energy Outlook*,[12] and PG&E's tariffed natural gas transportation rates.[13] MRW used a standard methodology of multiplying the natural gas price by the expected heat rate for a gas-fired unit and adding in variable operations and maintenance costs to calculate total power production costs.

In addition to power production costs, the cost of energy generated in or delivered to California also includes the cost of greenhouse gas allowances that, per the state's cap-and-trade program, must be procured to cover the greenhouse gases emitted by the energy generation. MRW estimated the price of GHG allowances to equal the auction floor price stipulated by the ARB's cap-and-trade regulation, consistent with recent auction outcomes.[14] MRW estimated the

[11] Capital cost for local solar projects in Contra Costa County, according to SAGE price curve, is $1,350 per kW installed for the first 400MW solar installed in the county. MRW calculated the average price for the cumulative developed capacity forecast for each year (counting only 50% of the capacity of each developed project towards the cumulative total). The total $1,350for kW installed doesn't include the soft and land acquisition/opportunity costs.

[12] U.S. Energy Information Administration. "2016 Annual Energy Outlook," Table 13.

[13] Pacific Gas & Electric, Burnertip Transporation Charges. Tariff G-EG, Advice Letter 3664-G, January 2016 and Tariff G-SUR, Advice Letter 3699-G, April 2016.

[14] California Code of Regulations, Title 17, Article 5, Section 95911.

emissions rate of Contra Costa County CCA non-renewable power supply based on an estimated heat rate for market power multiplied by the emissions factor for natural gas combustion.[15]

Capacity Cost Forecast for Non-Renewable Power

To estimate Contra Costa County CCA's capacity requirements, MRW developed a forecast of Contra Costa County CCA's peak demand in each year and subtracted the net qualifying capacity credits provided by Contra Costa County CCA's renewable power purchases. This is appropriate because the renewable energy prices used in this analysis reflect prices for contracts that supply both energy and capacity. If Contra Costa County CCA purchases renewable energy via energy-only contracts, Contra Costa County CCA's need for capacity will be greater than forecasted here, but these higher costs will be fully offset by the lower costs for the renewable energy.

MRW estimated current peak demand for Contra Costa County CCA's load using the 2015 monthly bills for all the current PG&E clients in Contra Costa County County[16] and PG&E's class-average load profiles. We forecasted changes to this peak demand based on the Contra Costa load forecast.[17] We calculated capacity requirements as 115% of the expected peak demand in order to include sufficient capacity to fulfill resource adequacy requirements. We applied a consistent methodology to obtain the peak demand growth rates and capacity requirements for PG&E.

To estimate the cost of Contra Costa County CCA's capacity needs, MRW priced capacity purchases at the median price of recent Resource Adequacy purchases, escalated with inflation.[18]

To estimate the cost of Contra Costa County CCA's capacity needs, MRW considered two time periods: the period before system load-resource balance when there is excess capacity on the system, and the period following system-load resource balance when additional supply must be developed. MRW assumed a system load-resource balance year of 2030.[19] Through 2025, MRW priced capacity at the median price of recent resource adequacy purchases, escalated with inflation. MRW increased the capacity price incrementally starting in 2026 to reflect an increase in the market price for capacity during the transition from the lower near-term prices to the higher post-load-resource balance prices. MRW assumed that Contra Costa County CCA would

[15] U.S. EIA. Electric Power Annual (EPA), February 16, 2016, Table A.3. https://www.eia.gov/electricity/annual/html/epa_a_03.html

[16] Monthly bills corresponding to 2015 for all the clients in Contra Costa County provided by PG&E.

[17] California Energy Commission. Demand Forecast. PG&E Forecast Zone Results Mid Demand Case, Sales Forecast, Central Valley Region. December 14, 2015.

[18] CPUC 2013-2014 Resource Adequacy Report Final, August 5, 2015, page 23 Table 11.

[19] According to the assumption adopted by the CPUC in December 2015 for long-term forecasting purposes, the load resource balance year was 2035. MRW opted to advance this to 2030 due to the retirement of the Diablo Canyon nuclear facility.

build its own power plant (alone or in combination with other public entities) in place of purchasing market capacity when market prices rise above the cost of a new self-build. In MRW's model, this occurs in 2030. From this point on, MRW assumed that the market price for Contra Costa County CCA's capacity would be equal to the levelized fixed cost of a new advanced combustion turbine developed by a publicly owned utility, minus levelized gross margins from energy sales. A similar methodology was used to forecast the cost of capacity for PG&E; however, PG&E's post-load-resource balance price forecast is based on the price of a combustion turbine developed by a merchant developer (see Appendix C).

Appendix C. Forecast of PG&E's Generation Rates

MRW developed a forecast of PG&E's generation rates for comparison with the rates that Contra Costa County CCA will need to charge to cover its costs of service. MRW developed the forecast for the years 2018-2038 using publicly available inputs, including cost and procurement data from PG&E, market price data, and data from California state regulatory agencies and the U.S. Energy Information Administration. The structure of the rate forecast model and the basic assumptions and inputs used are described below.

Generation Charges

PG&E's generation costs fall into four broad categories: (1) renewable generation costs, (2) fixed costs of non-renewable utility-owned generation, (3) fuel and purchased power costs for non-renewable generation, and (4) capacity costs. Each of these categories is evaluated separately in the rate forecast model, and underlying these forecasts is a forecast of PG&E's generation sales.

Sales Forecast

PG&E's generation cost forecast is driven in large part by the amount of generation that PG&E will need to obtain to meet customer demand. To forecast PG&E's electricity sales, MRW started with the 2016-2030 sales forecast that PG&E provided in its August 2016 Renewable Energy Procurement Plan ("RPS Plan") filing with the CPUC.[20] This forecast predicts an 8% annual sales reduction through 2020, a 2% reduction per year from 2021-2028, and a rather anemic sales growth of 0.2% per year from 2029-2030.[21] MRW extended the sales forecast through 2038, maintaining this 0.2% increase per year.

Renewable Generation

The starting point for MRW's analysis is PG&E's "RPS Plan," in which PG&E discusses its plan for meeting California's Renewable Portfolio Standard (RPS) targets and provides the annual amount and cost of renewable generation currently under contract through 2030. PG&E's RPS Plan shows that PG&E's current renewable procurement is in excess of the RPS requirement in each year through 2026. After 2022, PG&E's renewable generation from current contracts falls below the RPS requirements, but PG&E is projected to have enough banked Renewable Energy Credits (RECs) from excess renewable procurement in prior years to meet the RPS requirements until 2034.

[20] Pacific Gas & Electric. *Renewables Portfolio Standard 2016 Renewable Energy Procurement Plan (Draft Version).* August 8, 2016. Appendix D.

[21] The near-term decline in sales in PG&E's forecast is likely attributable to the growth in CCA, in which a municipality procures electric power on behalf of its constituents instead of having them purchase their power from PG&E. While customers in the jurisdictions of these municipalities have the option to opt-out of CCA and to continue to procure power from PG&E, so far, most CCA-eligible customers have not elected for this option. CCA customers continue to procure electricity delivery services from PG&E; it is only generation services that they obtain through the CCA.

MRW adopted PG&E's RPS Plan forecast of the amount and cost of renewable generation that is currently under contract. For the period starting in 2034 when PG&E's RPS Plan shows a need for incremental renewable procurement to meet RPS requirements, MRW added in the necessary renewable generation to meet current statutory requirements (i.e., 33% of procurement in 2020, increasing to 50% of procurement in 2030, and to 55% of procurement in 2031).[22] To project PG&E's cost of this incremental renewable generation, MRW used the same renewable prices used for Contra Costa County CCA's renewable power cost forecast (see Appendix B).

Fixed Cost of Non-Renewable Utility-Owned Generation

PG&E's rates include payment for the fixed costs of the PG&E-owned non-renewable generation facilities, which are primarily natural gas, nuclear, and hydroelectric power plants. Because these costs are not tied to the volume of electricity that PG&E sells, their annual escalation is not driven by the price of fuel and other variable inputs. Instead, they escalate at a rate that stems from a combination of cost increases and depreciation reductions. These escalation rates are determined in General Rate Case (GRC) proceedings, which occur roughly every three years.

As a starting point for the forecast, MRW used the proposed 2017 fixed costs for these facilities.[23] For the period between 2018 and 2020, MRW increased the fixed cost based on PG&E's 2017 GRC settlements.[24] For subsequent years, MRW estimated in the base case that PG&E's generation fixed costs would increase by the 6.2% annual average growth rate approved and implemented for these cost over the last ten years.[25] These escalation rates are in nominal dollars (i.e., some of the escalation is accounted for by inflation).

[22] MRW additionally allowed for the purchase of additional renewable generation when renewable prices are below market prices, subject to some purchase limits, including a 50% cap on renewable generation relative to the entire generation portfolio. This leads to additional renewable purchases from 2027-2029 in the Low Renewable Price scenario. Starting in 2030, the RPS requirement is 50%, and no additional renewable purchases are allowed, per the rules of the model, in order to maintain grid reliability.

[23] Pacific Gas & Electric. Annual Electric True-Ups for 2017. Advice Letter 4902 E-A. September 13, 2016. Table 2 and Pacific Gas & Electric 2017 GRC Settlements, A.15-09-001, Appendix A and B.

[24] Pacific Gas & Electric 2017 GRC Settlements, A.15-09-001, Appendix A and B

[25] Historic growth rates calculated from Pacific Gas & Electric Advice Letters 2706-E-A, AL 3773-E, 4459-E, 4647-E, and 4755-E. New power plant costs were excluded from these calculations since costs of new plants are offset, at least in part, by a reduction in fuel and purchased power costs.

Table 1: PG&E's Generation Fixed Costs, 2011-2016[26]
(Nominal $ Million)

	2011	2012	2013	2014	2015	2016
Generation Fixed Costs	1,400	1,530	1,550	1,710	1,860	1,840
Annual Cost Increase		9%	1%	10%	9%	-1%

MRW made adjustments to this GRC forecast to account for the retirement of the Diablo Canyon nuclear units at the end of the units' current licenses in 2024 and 2025.

Fuel and Purchased Power Costs for Non-Renewable Generation

Each spring, PG&E files a forecast with the CPUC of its fuel and purchased power costs for the upcoming year in its "ERRA" filing, which PG&E updates and finalizes in November. MRW relied on PG&E's November 2017 ERRA testimony,[27] adjusted to remove renewable generation costs, as the starting point for the forecast of fuel and purchased power costs for PG&E's non-renewable generation.

To escalate these costs through the forecast period, MRW forecasted changes to natural gas prices and greenhouse gas cap-and-trade program compliance costs, which are the major drivers of change to these costs. The natural gas price forecast is based on current NYMEX market futures prices for natural gas, forecasted natural gas prices in the U.S. EIA's 2016 *Annual Energy Outlook*, and PG&E's tariffed natural gas transportation rates. This forecast is the same forecast used in the forecast of Contra Costa County CCA's wholesale power costs (see Appendix B).

Cap-and-trade program compliance costs are estimated based on (1) PG&E's forecast of carbon dioxide emissions in 2017;[28] (2) a forecast of PG&E's fossil generation supply, developed by subtracting expected renewable, hydroelectric, and nuclear generation from PG&E's projected wholesale power requirement; and (3) a forecast of greenhouse gas allowance prices. The greenhouse gas allowance price forecast is the same as used in the forecast of Contra Costa County CCA wholesale power costs and is based on the auction floor price stipulated by the ARB's cap-and-trade regulation (see Appendix B).

[26] 2011-2013: CPUC Decision 11-05-018, pages 2 and 15; and 2014-2016: CPUC Decision 14-08-032, Appendix C, Table 1 and Appendix D, Table 1.

[27] PG&E Update To Prepared 2017 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation, filed with the CPUC in proceeding A.16-06-003 on Nov 2, 2016, Table 11-3.

[28] PG&E Update To Prepared 2017 Energy Resource Recovery Account and Generation Non-Bypassable Charges Forecast and Greenhouse Gas Forecast Revenue and Reconciliation, filed with the CPUC in proceeding A.16-06-003 on Nov 2, 2016, Table 12-2.

The MRW rate model calculates total fuel and purchased power costs by escalating natural gas prices based on the natural gas price forecast described above, escalating nuclear fuel prices based on the EIA forecast of fuel costs for nuclear plants, escalating water costs for hydroelectric projects and the capacity costs of power purchase contracts with inflation, and pricing market power at the same market power price used for Contra Costa County CCA's purchases. The model then sums the cost for each of these resources and adds in projected cap-and-trade compliance costs to this total cost.

Capacity Costs

PG&E must procure capacity to meet 115% of its anticipated peak demand in order to fulfill its resource adequacy requirement. PG&E's own power plants can be used to meet this requirement, as can power plants with which PG&E has contracts.

To estimate PG&E's capacity requirements, MRW started with the Capacity Supply Plan that PG&E submitted to the California Energy Commission in 2015,[29] which forecasts PG&E's peak demand and existing capacity resources for each of the years 2013-2024. With limited exception,[30] MRW used PG&E's data where publicly available and extended the forecasts to 2038. In extending these forecasts, we used assumptions that are consistent with those used in our assessments of energy sales and costs, including load growth escalation and the projected retirement of PG&E's nuclear plant. We also added in anticipated capacity from new renewable procurement and from new energy storage and adjusted the calculation to account for the portion of Resource Adequacy credits that is allocated to non-bundled customers.

As with the Contra Costa County CCA's capacity cost forecast, MRW priced capacity at the median price of recent Resource Adequacy capacity sales, escalated with inflation.[31]

Rate Development

Following the methodologies described above, MRW developed a forecast of PG&E's generation revenue requirement and divided these expenses by the expected PG&E sales in order to obtain a forecast of the system-average generation rate. We calculated annual escalators based on these system-average rates and applied them to the generation rates that are currently in effect for each customer class.[32]

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[29] California Energy Commission, Energy Almanac, Utility Capacity Supply Plans from 2015. September 4, 2015

[30] The two main exceptions are that 1) MRW increased energy efficiency and demand response growth to comply with SB 350 requirements to double energy efficiency by 2030 and the anticipated continuation of CPUC demand response initiatives, and 2) MRW accounted for the energy efficiency and renewable capacity expected to be installed because of the Diablo Canyon retirement application.

[31] CPUC 2013-2014 Resource Adequacy Report Final, August 5, 2015, page 23 Table 11.

[32] PG&E Advice Letter AL-4805-E, effective March 24, 2016.

Appendix D. Detailed CCA Rates

Case-Legend	
Base	BASE
Low participation	LP
High price local	LOC
High renewable prices	RPS
High natural gas price	GAS
Low PG&E portfolio costs	LPGE
High PCIA	PCIA
Stress Scenario	STRS

Scenario	Sensitivity Case	Rates (¢/kWh)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
1	BASE	CCA gen	7.0	7.1	7.1	7.4	7.6	7.8	7.9	8.0	8.4	8.8	9.3	9.9	10.5	10.8	11.1	11.4	11.7	12.0	12.4	12.7	13.1
1	BASE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
1	BASE	CCA Res Fund	0.8	0.7	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	BASE	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
1	LP	CCA gen	7.1	7.2	7.2	7.5	7.7	7.9	8.0	8.1	8.5	8.9	9.4	9.9	10.5	10.8	11.1	11.4	11.8	12.1	12.4	12.8	13.2
1	LP	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
1	LP	CCA Res Fund	0.6	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	LP	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
1	LOC	CCA gen	7.0	7.1	7.1	7.4	7.6	7.8	7.9	8.0	8.4	8.8	9.3	9.9	10.5	10.8	11.1	11.4	11.7	12.0	12.4	12.7	13.1
1	LOC	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
1	LOC	CCA Res Fund	0.8	0.7	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	LOC	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
1	RPS	CCA gen	7.1	7.2	7.3	7.8	8.1	8.5	8.6	8.8	9.2	9.7	10.2	10.8	11.4	11.8	12.2	12.5	12.9	13.2	13.6	14.0	14.4
1	RPS	Exit fees	2.4	1.9	2.3	1.6	1.6	1.5	1.3	1.1	0.9	0.7	0.6	0.5	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0
1	RPS	CCA Res Fund	0.7	0.7	0.4	0.1	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	RPS	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.5	11.4	11.1	11.5	12.2	12.9	13.8	14.9	15.7	16.5	17.3	17.3	17.8	18.4	18.7	19.4
1	GAS	CCA gen	8.1	8.5	8.8	9.2	9.5	9.4	9.4	9.6	10.0	10.4	10.8	11.3	11.9	12.3	12.6	12.9	13.3	13.7	14.2	14.6	15.0
1	GAS	Exit fees	2.2	2.6	2.7	2.8	2.6	3.4	2.4	1.7	0.8	0.7	0.7	0.6	0.5	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1
1	GAS	CCA Res Fund	0.2	-0.1	0.0	0.0	0.0	0.0	0.0	1.4	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	GAS	PG&E gen	10.5	10.9	11.0	11.4	11.9	11.0	11.3	11.8	12.3	12.9	13.5	14.3	15.3	15.4	15.8	16.2	16.7	17.1	17.7	18.3	19.0
1	LPGE	CCA gen	7.0	7.1	7.1	7.4	7.6	7.8	7.9	8.0	8.4	8.8	9.3	9.9	10.5	10.8	11.1	11.4	11.7	12.0	12.4	12.7	13.1
1	LPGE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
1	LPGE	CCA Res Fund	0.0	1.1	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	LPGE	PG&E gen	9.1	9.5	9.6	10.1	10.4	10.2	10.2	9.8	10.2	10.7	11.4	12.1	13.0	13.2	13.6	14.0	14.5	14.9	15.3	15.8	16.4
1	PCIA	CCA gen	7.0	7.1	7.1	7.4	7.6	7.8	7.9	8.0	8.4	8.8	9.3	9.9	10.5	10.8	11.1	11.4	11.7	12.0	12.4	12.7	13.1
1	PCIA	Exit fees	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

1	PCIA	CCA Res Fund	0.8	0.7	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
1	PCIA	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
1	STRS	CCA gen	8.2	8.7	9.1	9.6	9.9	10.1	10.2	10.3	10.8	11.2	11.7	12.3	12.9	13.3	13.7	14.1	14.6	15.0	15.4	15.9	16.4
1	STRS	Exit fees	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
1	STRS	CCA Res Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	STRS	PG&E gen	9.4	9.8	9.9	10.2	10.7	9.9	10.2	10.6	11.3	11.8	12.4	13.2	14.0	14.3	14.8	15.3	15.7	16.2	16.8	17.4	18.1

Scenario	Sensitivity Case	Rates (¢/kWh)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
2	BASE	CCA gen	7.2	7.3	7.3	7.6	7.8	8.0	8.0	8.3	8.6	9.1	9.5	10.0	10.6	10.8	11.1	11.3	11.6	11.9	12.1	12.4	12.7
2	BASE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
2	BASE	CCA Res Fund	0.6	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
2	BASE	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
2	LP	CCA gen	7.3	7.4	7.4	7.6	7.8	8.1	8.1	8.3	8.7	9.1	9.6	10.1	10.6	10.9	11.1	11.4	11.7	11.9	12.2	12.5	12.8
2	LP	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
2	LP	CCA Res Fund	0.5	0.9	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
2	LP	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
2	LOC	CCA gen	7.2	7.3	7.3	7.6	7.8	8.0	8.0	8.3	8.6	9.1	9.5	10.0	10.6	10.8	11.1	11.3	11.6	11.9	12.1	12.4	12.7
2	LOC	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
2	LOC	CCA Res Fund	0.6	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
2	LOC	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
2	RPS	CCA gen	7.3	7.5	7.6	8.2	8.5	9.1	9.2	9.5	10.0	10.5	11.0	11.6	12.3	12.5	12.8	13.1	13.4	13.7	14.0	14.4	14.7
2	RPS	Exit fees	2.4	1.9	2.3	1.6	1.6	1.5	1.3	1.1	0.9	0.7	0.6	0.5	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0
2	RPS	CCA Res Fund	0.5	0.9	0.4	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
2	RPS	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.5	11.4	11.1	11.5	12.2	12.9	13.8	14.9	15.7	16.5	17.3	17.3	17.8	18.4	18.7	19.4
2	GAS	CCA gen	8.0	8.3	8.7	9.0	9.3	8.9	9.0	9.2	9.6	9.9	10.3	10.8	11.3	11.6	11.9	12.2	12.5	12.8	13.1	13.4	13.8
2	GAS	Exit fees	2.2	2.6	2.7	2.8	2.6	3.4	2.4	1.7	0.8	0.7	0.7	0.6	0.5	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1
2	GAS	CCA Res Fund	0.3	0.0	-0.1	0.0	1.4	-1.4	0.0	1.4	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1
2	GAS	PG&E gen	10.5	10.9	11.0	11.4	11.9	11.0	11.3	11.8	12.3	12.9	13.5	14.3	15.3	15.4	15.8	16.2	16.7	17.1	17.7	18.3	19.0
2	LPGE	CCA gen	7.2	7.3	7.3	7.6	7.8	8.0	8.0	8.3	8.6	9.1	9.5	10.0	10.6	10.8	11.1	11.3	11.6	11.9	12.1	12.4	12.7
2	LPGE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
2	LPGE	CCA Res Fund	0.0	1.1	0.0	0.4	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
2	LPGE	PG&E gen	9.1	9.5	9.6	10.1	10.4	10.2	10.2	9.8	10.2	10.7	11.4	12.1	13.0	13.2	13.6	14.0	14.5	14.9	15.3	15.8	16.4
2	PCIA	CCA gen	7.2	7.3	7.3	7.6	7.8	8.0	8.0	8.3	8.6	9.1	9.5	10.0	10.6	10.8	11.1	11.3	11.6	11.9	12.1	12.4	12.7
2	PCIA	Exit fees	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

2	PCIA	CCA Res Fund	0.6	0.8	0.4	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
2	PCIA	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
2	STRS	CCA gen	8.2	8.6	9.0	9.7	9.9	10.1	10.2	10.5	10.9	11.4	11.9	12.4	13.0	13.4	13.7	14.0	14.4	14.7	15.1	15.4	15.8
2	STRS	Exit fees	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
2	STRS	CCA Res Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	STRS	PG&E gen	9.4	9.8	9.9	10.2	10.7	9.9	10.2	10.6	11.3	11.8	12.4	13.2	14.0	14.3	14.8	15.3	15.7	16.2	16.8	17.4	18.1

Scenario	Sensitivity Case	Rates (¢/kWh)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
3	BASE	CCA gen	7.1	7.2	7.4	7.8	8.1	8.5	8.7	9.0	9.6	10.3	10.8	11.4	12.0	12.4	12.7	13.1	13.4	13.7	14.1	14.4	14.8
3	BASE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
3	BASE	CCA Res Fund	0.7	0.7	0.4	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	BASE	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
3	LP	CCA gen	7.2	7.4	7.5	7.9	8.2	8.6	8.8	9.1	9.6	10.3	10.8	11.4	12.0	12.4	12.7	13.1	13.4	13.7	14.1	14.4	14.8
3	LP	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
3	LP	CCA Res Fund	0.6	0.8	0.4	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	LP	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
3	LOC	CCA gen	7.1	7.3	7.5	7.9	8.3	8.8	9.1	9.4	10.1	10.8	11.4	12.0	12.6	13.0	13.4	13.8	14.1	14.5	14.8	15.1	15.5
3	LOC	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
3	LOC	CCA Res Fund	0.7	0.8	0.4	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	LOC	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
3	RPS	CCA gen	7.1	7.4	7.6	8.2	8.6	9.3	9.6	10.0	10.6	11.4	12.0	12.6	13.4	13.8	14.2	14.7	15.0	15.4	15.8	16.1	16.5
3	RPS	Exit fees	2.4	1.9	2.3	1.6	1.6	1.5	1.3	1.1	0.9	0.7	0.6	0.5	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0
3	RPS	CCA Res Fund	0.6	0.8	0.4	0.1	0.1	0.1	0.0	0.1	0.0	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	RPS	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.5	11.4	11.1	11.5	12.2	12.9	13.8	14.9	15.7	16.5	17.3	17.3	17.8	18.4	18.7	19.4
3	GAS	CCA gen	8.1	8.6	9.0	9.5	9.8	10.1	10.3	10.6	11.2	11.8	12.3	12.9	13.5	13.9	14.3	14.7	15.1	15.5	15.9	16.3	16.7
3	GAS	Exit fees	2.2	2.6	2.7	2.8	2.6	3.4	2.4	1.7	0.8	0.7	0.7	0.6	0.5	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1
3	GAS	CCA Res Fund	0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	1.7	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	GAS	PG&E gen	10.5	10.9	11.0	11.4	11.9	11.0	11.3	11.8	12.3	12.9	13.5	14.3	15.3	15.4	15.8	16.2	16.7	17.1	17.7	18.3	19.0
3	LPGE	CCA gen	7.1	7.2	7.4	7.8	8.1	8.5	8.7	9.0	9.6	10.3	10.8	11.4	12.0	12.4	12.7	13.1	13.4	13.7	14.1	14.4	14.8
3	LPGE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
3	LPGE	CCA Res Fund	0.0	1.1	-0.1	0.6	0.1	0.1	0.0	-0.5	-0.3	-0.3	-0.1	1.7	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
3	LPGE	PG&E gen	9.1	9.5	9.6	10.1	10.4	10.2	10.2	9.8	10.2	10.7	11.4	12.1	13.0	13.2	13.6	14.0	14.5	14.9	15.3	15.8	16.4
3	PCIA	CCA gen	7.1	7.2	7.4	7.8	8.1	8.5	8.7	9.0	9.6	10.3	10.8	11.4	12.0	12.4	12.7	13.1	13.4	13.7	14.1	14.4	14.8
3	PCIA	Exit fees	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

3	PCIA	CCA Res Fund	0.7	0.7	0.4	0.1	0.1	0.1	0.0	-0.5	-0.7	-0.2	0.0	0.0	1.8	-0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1
3	PCIA	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
3	STRS	CCA gen	8.3	8.9	9.4	10.1	10.5	11.2	11.6	12.0	12.8	13.6	14.2	14.9	15.6	16.2	16.7	17.2	17.6	18.1	18.5	19.0	19.5
3	STRS	Exit fees	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
3	STRS	CCA Res Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	STRS	PG&E gen	9.4	9.8	9.9	10.2	10.7	9.9	10.2	10.6	11.3	11.8	12.4	13.2	14.0	14.3	14.8	15.3	15.7	16.2	16.8	17.4	18.1

Scenario	Sensitivity Case	Rates (¢/kWh)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
4	BASE	CCA gen	7.3	7.6	7.8	8.3	8.7	9.2	9.6	10.3	11.1	12.0	12.6	13.2	13.9	14.1	14.4	14.6	14.9	15.2	15.5	15.7	16.1
4	BASE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
4	BASE	CCA Res Fund	0.4	0.9	0.4	0.1	0.1	0.1	0.1	-0.6	-0.7	-0.1	0.0	0.0	2.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
4	BASE	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
4	LP	CCA gen	7.5	7.7	7.9	8.3	8.8	9.3	9.6	10.3	11.0	11.9	12.5	13.1	13.7	14.0	14.2	14.5	14.8	15.0	15.3	15.6	15.9
4	LP	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
4	LP	CCA Res Fund	0.3	1.0	0.4	0.1	0.1	0.1	0.1	-0.6	-0.6	-0.2	0.0	0.0	2.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
4	LP	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
4	LOC	CCA gen	7.4	7.7	8.0	8.5	9.1	9.7	10.2	11.0	11.9	12.9	13.6	14.2	15.0	15.2	15.5	15.8	16.1	16.3	16.6	16.9	17.2
4	LOC	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
4	LOC	CCA Res Fund	0.4	1.0	0.4	0.1	0.1	0.1	-0.3	-1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	0.1	0.1	0.1	0.1
4	LOC	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
4	RPS	CCA gen	7.4	7.8	8.1	8.9	9.6	10.6	11.1	11.9	12.9	14.0	14.7	15.4	16.3	16.6	16.9	17.2	17.5	17.9	18.2	18.5	18.9
4	RPS	Exit fees	2.4	1.9	2.3	1.6	1.6	1.5	1.3	1.1	0.9	0.7	0.6	0.5	0.5	0.4	0.3	0.1	0.0	0.0	0.0	0.0	0.0
4	RPS	CCA Res Fund	0.4	1.0	0.5	0.1	0.1	-0.6	-0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7	0.1	0.1
4	RPS	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.5	11.4	11.1	11.5	12.2	12.9	13.8	14.9	15.7	16.5	17.3	17.3	17.8	18.4	18.7	19.4
4	GAS	CCA gen	8.1	8.6	9.0	9.6	9.9	10.2	10.6	11.3	12.1	13.0	13.5	14.1	14.7	15.0	15.3	15.7	16.0	16.3	16.6	17.0	17.3
4	GAS	Exit fees	2.2	2.6	2.7	2.8	2.6	3.4	2.4	1.7	0.8	0.7	0.7	0.6	0.5	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1
4	GAS	CCA Res Fund	0.1	-0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
4	GAS	PG&E gen	10.5	10.9	11.0	11.4	11.9	11.0	11.3	11.8	12.3	12.9	13.5	14.3	15.3	15.4	15.8	16.2	16.7	17.1	17.7	18.3	19.0
4	LPGE	CCA gen	7.3	7.6	7.8	8.3	8.7	9.2	9.6	10.3	11.1	12.0	12.6	13.2	13.9	14.1	14.4	14.6	14.9	15.2	15.5	15.7	16.1
4	LPGE	Exit fees	2.4	1.9	2.3	1.7	1.7	1.6	1.5	1.3	0.9	0.8	0.7	0.6	0.5	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
4	LPGE	CCA Res Fund	0.0	1.1	-0.5	1.0	0.1	-0.5	-0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	0.1
4	LPGE	PG&E gen	9.1	9.5	9.6	10.1	10.4	10.2	10.2	9.8	10.2	10.7	11.4	12.1	13.0	13.2	13.6	14.0	14.5	14.9	15.3	15.8	16.4
4	PCIA	CCA gen	7.3	7.6	7.8	8.3	8.7	9.2	9.6	10.3	11.1	12.0	12.6	13.2	13.9	14.1	14.4	14.6	14.9	15.2	15.5	15.7	16.1
4	PCIA	Exit fees	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4

4	PCIA	CCA Res Fund	0.4	0.9	0.4	0.1	0.1	-0.2	-0.6	-0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	PCIA	PG&E gen	10.1	10.6	10.7	11.3	11.6	11.4	11.3	10.9	11.3	11.9	12.6	13.4	14.4	14.7	15.1	15.6	16.1	16.5	17.1	17.6	18.3
4	STRS	CCA gen	8.4	9.0	9.6	10.5	11.2	12.1	12.7	13.7	14.8	16.1	16.8	17.5	18.3	18.7	19.0	19.4	19.8	20.2	20.6	21.0	21.4
4	STRS	Exit fees	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
4	STRS	CCA Res Fund	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	STRS	PG&E gen	9.4	9.8	9.9	10.2	10.7	9.9	10.2	10.6	11.3	11.8	12.4	13.2	14.0	14.3	14.8	15.3	15.7	16.2	16.8	17.4	18.1

Appendix E. Greenhouse Gas Emissions and Costs

In Chapter 3 of the report, MRW provided an estimate of Contra Costa County CCA's annual Greenhouse Gas (GHG) emissions and compared these with the emissions for the same load under the PG&E supply portfolio. The methodology used to calculate both figures is included in this appendix, along with an estimate of Contra Costa County CCA's cost of emissions from purchased power ("indirect emissions").

Methodology for calculating Contra Costa County CCA's indirect GHG emissions

GHG emissions for Contra Costa County CCA will be indirect since the CCA does not plan to generate its own power (*i.e.,* the emissions are embedded in fossil-fuel power that the CCA purchases). These emissions are estimated based on (1) a forecast of the emissions rate for Contra Costa County CCA's fossil generation supply and (2) a forecast of the amount of Contra Costa County CCA's fossil generation supply, developed by subtracting expected renewable and hydroelectric generation from the projected wholesale power requirement to serve the CCA's load.[33]

MRW calculated the emissions rate for Contra Costa County CCA's fossil generation supply by estimating the amount of natural gas that will need to be burned to generate the CCA's fossil generation and the GHG emissions rate for natural gas combustion.[34] The amount of natural gas needed was estimated based on the average heat rate for the marginal generation plants on the CAISO system. MRW used public data from CAISO's OASIS platform and Platt's Gas Daily reports to calculate this average heat rate for 2015.[35] MRW extended the forecast to 2030 using the expected changes to the average heat rate in California from the EIA's 2016 *Annual Energy Outlook.*[36]

MRW estimated the total annual GHG emissions for the Contra Costa County CCA program as a product of the total energy purchased at wholesale electric market (kWh) and the rate of GHG emissions (tonnes $CO_{2\text{-equivalent}}$/kWh).

[33] MRW assumed no GHG emissions for the renewable and hydroelectric supply.

[34] The GHG emissions rate for natural gas combustion is obtained from U.S. EIA. Electric Power Annual (EPA), February 16, 2016, Table A.3. https://www.eia.gov/electricity/annual/html/epa_a_03.html

[35] MRW calculated the average heat rate of the marginal generation plants in 2015 by dividing the monthly average wholesale electric market price, net of operations and maintenance costs and GHG emissions costs, by the monthly average natural gas price. For the electricity prices, we used the average of the 2015 hourly locational marginal price for node TH_NP15_GEN-APND; for the natural gas prices, we used the average of burnertip natural gas price for PG&E.

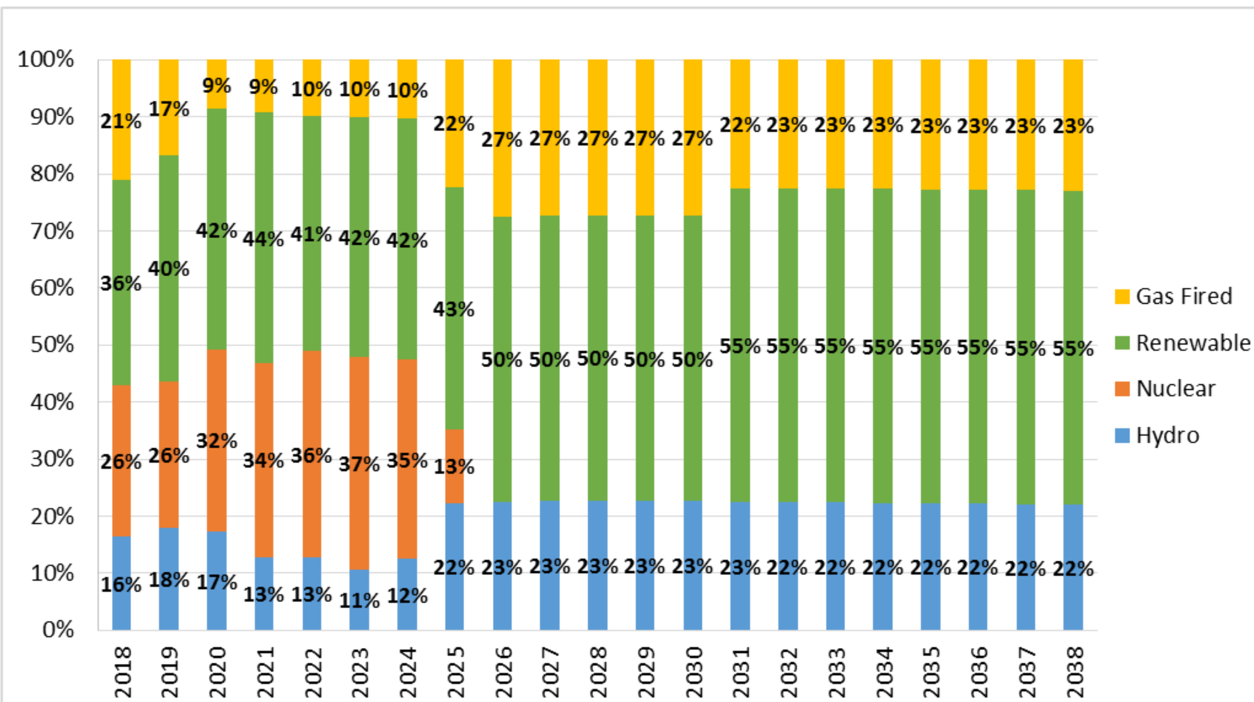
[36] U.S. Energy Information Administration. "2016 Annual Energy Outlook," Table 55.20, Western Electricity Coordinating Council. (Note that EIA does not provide a forecast of the marginal heat rate.)

Methodology for calculating GHG emissions under PG&E's supply portfolio

MRW calculated the GHG emissions for the Contra Costa County CCA load under the PG&E supply portfolio by summing the emissions from all resources in PG&E's portfolio. MRW assumed no GHG emissions from renewable power, hydroelectric power, or nuclear generation. In order to maintain a consistent comparison, MRW used the same emissions rate to calculate the emissions from PG&E's fossil-fuel power as used for the Contra Costa County CCA wholesale market purchases.

In order to support the analysis on Chapter 3 of the report, Figure 2 shows the PG&E portfolio. Before the closure of the Diablo Canyon, MRW estimated 80%-90% of PG&E's generation portfolio based on non-fuel-fired resources. After 2025, the non-fuel-fired resources share falls to 70% according MRW estimates.

Figure 2 PG&E's generation portfolio[37]



[37] Before 2025 the hydroelectric generation is below its potential because MRW estimated that PG&E sells the over-procurement in hydroelectric power. MRW has assumed a minimum of fuel-fired generation to facilitate the RPS integration according to PG&E's Diablo Canyon retirement application, A.16-08-006. Table 2-3. In addition, after 2026 MRW estimated the price of the wholesale electric market below PG&E's new RPS prices. In those conditions, according to MRW assumptions, PG&E would procure up to 50% of its portfolio from renewable resources.

GHG allowance prices and GHG indirect costs

MRW developed a forecast of the prices for GHG allowances based on the auction floor price stipulated by the ARB's cap-and-trade regulation, consistent with recent auction outcomes.[38]

Table 2 GHG Allowances price, $ per allowance[39]

	2017	2018	2019	2025	2030	2035	2038
$/tonne	13.2	14.7	15.9	24.4	34.7	49.8	61.8

MRW used these GHG allowances prices to calculate both PG&E's GHG allowances costs (direct and indirect), which are included in the PG&E rate forecast, and Contra Costa County CCA's indirect GHG costs. The indirect GHG costs for Contra Costa County CCA will be included in the cost of the wholesale market energy purchases. MRW estimated that these costs will be, on average, $12 per MWh delivered over the 2018-2038 period.

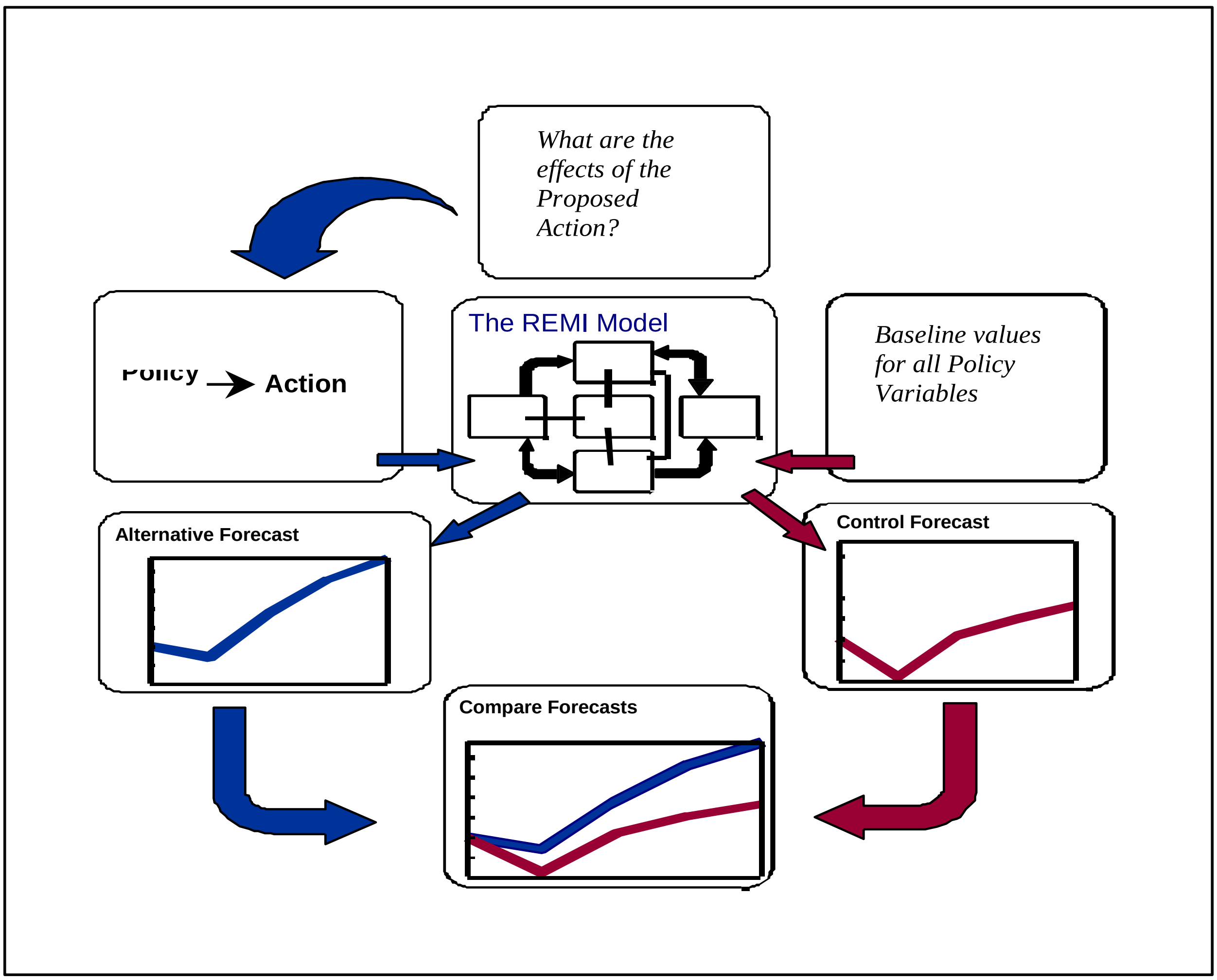
[38] California Code of Regulations, Title 17, Article 5, Section 95911.

[39] For 2017, the amount listed corresponds to the GHG allowance price for PG&E according to the most recent ERRA 2017 update. Pacific Gas & Electric ERRA 2017, A.16-06-003, Testimony November 2, 2016, Table 12-1.

Appendix F. About the REMI Policy Insight Model

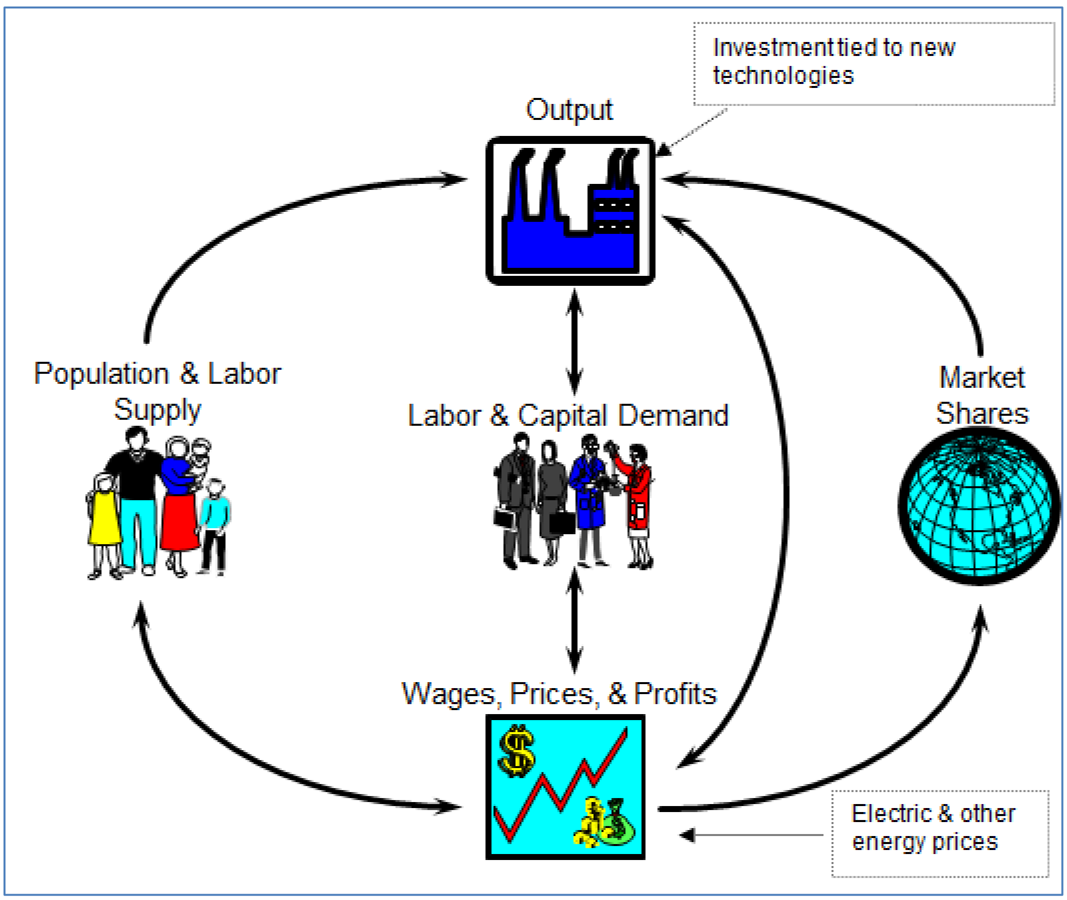
A software analysis forecasting model developed by Regional Economic Models, Inc. (REMI) of Amherst Massachusetts in the mid 1980's. It has a broad national customer base among public agencies, academic institutions, and the private-sector. It is also used in Canada (NRCan), and among other international clients. The model configuration used for this study consisted of 18 aggregate private-sector industries, plus a farm sector, a combined state/local government sector and two federal government sectors.

Economic Impacts Identified with the REMI Model



In the above figure, the central box "The REMI model" is the engine for predicting the economic and demographic dimensions of a *region-of-impact* (here Contra Costa County County) under *no-action* (or Control forecast) and with a proposed CCA (alternative forecast). The engine is a combination structural econometric model, part input-output transactions, all with general equilibrium features – meaning *an economy can encounter a disruption (positive or negative), and over time (typically 1-3 years depending on the scale of the region and the size of the shock) re-adjust back to an equilibrium*. The diagram below depicts the organization of the REMI regional model in terms of the major blocks functioning in an economy and the arrows denote the feedback accounted for. Keep in mind this portrayal is at a very high-level, sparing the industry-specific details. Scenario specific changes are inserted through policy variable *levers* into the appropriate block of the model. There is another important dimension of economic response for the key region-of-impact that effectively layers on top of the below diagram – interactions with another regional economy. That additional region - *rest of California* -was explicitly modeled at the same time. The REMI model captures the flows of monetized goods and services, and commuter labor between regions when one (or both) is *shocked* by introduction of a CCA.

Core Logic of the REMI Model



Appendix G. Proforma Tables

Scenario 1

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Expenses											
Cost of Power (including losses)	$73,495,453	$151,069,291	$238,312,375	$248,611,457	$257,237,071	$265,886,720	$274,183,543	$279,728,463	$294,209,869	$310,824,883	$329,903,546
O&M/A&G Costs	$9,081,989	$11,047,477	$14,037,456	$14,312,982	$14,596,957	$14,871,929	$15,146,845	$15,425,482	$15,722,408	$16,025,074	$16,333,641
Energy Efficiency Programming Costs											
Total Expenses	**$82,577,443**	**$162,116,767**	**$252,349,831**	**$262,924,440**	**$271,834,028**	**$280,758,650**	**$289,330,388**	**$295,153,945**	**$309,932,277**	**$326,849,957**	**$346,237,187**
Debt Service	**$0**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$0**	**$0**	**$0**	**$0**	**$0**
Total Revenue Requirement	**$82,577,443**	**$167,605,774**	**$257,838,838**	**$268,413,446**	**$277,323,035**	**$286,247,656**	**$289,330,388**	**$295,153,945**	**$309,932,277**	**$326,849,957**	**$346,237,187**
Total Load, MWh	**1,177,121**	**2,366,944**	**3,607,181**	**3,623,598**	**3,641,698**	**3,652,169**	**3,659,921**	**3,666,956**	**3,680,582**	**3,694,258**	**3,707,985**
Contra Costa CCA Customer Charges, $/MWh (before Reserve Fund Adjustment)											
Average Contra Costa CCA generation	$70.2	$70.8	$71.5	$74.1	$76.2	$78.4	$79.1	$80.5	$84.2	$88.5	$93.4
PG&E average exit fees for CCA load	$23.7	$19.1	$22.9	$16.6	$16.6	$15.7	$14.6	$12.6	$9.1	$8.0	$7.0
Total CCA customer rate	**$93.8**	**$89.9**	**$94.3**	**$90.6**	**$92.7**	**$94.1**	**$93.6**	**$93.1**	**$93.3**	**$96.4**	**$100.4**
PG&E average gen rate for CCA load, $/MWh	**$101.5**	**$105.7**	**$106.6**	**$112.7**	**$115.5**	**$113.8**	**$113.3**	**$109.2**	**$113.2**	**$119.2**	**$126.3**
Reserve Fund Adjustment											
Target	$12,386,616	$25,140,866	$38,675,826	$40,262,017	$41,598,455	$42,937,148	$43,399,558	$44,273,092	$46,489,842	$49,027,494	$51,935,578
Reserve Fund Adjustment											
Potential Reserve potential	$9,037,817	$37,373,117	$44,318,310	$79,873,437	$82,994,739	$72,190,684	$72,076,358	$58,860,584	$73,135,250	$84,142,452	$96,221,651
Potential Reserve additions	$9,037,817	$16,103,049	$13,534,960	$1,586,191	$1,336,438	$1,338,693	$462,410	$873,533	$2,216,750	$2,537,652	$2,908,084
Subtractions from reserve fund	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reserve fund total	**$9,037,817**	**$25,140,866**	**$38,675,826**	**$40,262,017**	**$41,598,455**	**$42,937,148**	**$43,399,558**	**$44,273,092**	**$46,489,842**	**$49,027,494**	**$51,935,578**
Contra Costa CCA Customer Charges, $/MWh (with Reserve Fund Adjustment)											
Rate adjustment from Reserve Fund	$7.7	$6.8	$3.8	$0.4	$0.4	$0.4	$0.1	$0.2	$0.6	$0.7	$0.8
Average Contra Costa CCA rate	$77.8	$77.6	$75.2	$74.5	$76.5	$78.7	$79.2	$80.7	$84.8	$89.2	$94.2
PG&E average exit fees for CCA load	$23.7	$19.1	$22.9	$16.6	$16.6	$15.7	$14.6	$12.6	$9.1	$8.0	$7.0
Total CCA customer rate	**$101.5**	**$96.7**	**$98.1**	**$91.1**	**$93.1**	**$94.4**	**$93.8**	**$93.4**	**$93.9**	**$97.1**	**$101.2**
Contra Costa CCA CO2 emissions											
Emissions (Tonnes/MWh)	0.04	0.03	0.02	0.02	0.02	0.02	0.02	0.04	0.05	0.05	0.05
Total emissions (Tonnes)	48,104	76,449	70,394	71,051	71,298	72,351	73,983	158,002	195,517	194,741	195,332

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Expenses										
Cost of Power (including losses)	$350,515,984	$373,621,644	$386,946,608	$399,254,590	$411,812,091	$425,651,977	$439,658,506	$454,135,582	$468,721,683	$484,831,280
O&M/A&G Costs	$16,648,197	$16,968,859	$17,295,746	$17,628,978	$17,968,678	$18,314,999	$18,668,042	$19,027,938	$19,394,819	$19,768,820
Energy Efficiency Programming Costs										
Total Expenses	**$367,164,181**	**$390,590,503**	**$404,242,354**	**$416,883,567**	**$429,780,769**	**$443,966,976**	**$458,326,548**	**$473,163,520**	**$488,116,502**	**$504,600,100**
Debt Service	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Total Revenue Requirement	**$367,164,181**	**$390,590,503**	**$404,242,354**	**$416,883,567**	**$429,780,769**	**$443,966,976**	**$458,326,548**	**$473,163,520**	**$488,116,502**	**$504,600,100**
Total Load, MWh	**3,721,763**	**3,735,593**	**3,749,473**	**3,763,406**	**3,777,390**	**3,791,426**	**3,805,514**	**3,819,655**	**3,833,848**	**3,848,093**
Contra Costa CCA Customer Charges, $/MWh (before Reserve Fund Adjustment)										
Average Contra Costa CCA generation	$98.7	$104.6	$107.8	$110.8	$113.8	$117.1	$120.4	$123.9	$127.3	$131.1
PG&E average exit fees for CCA load	$6.0	$5.1	$3.1	$1.7	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0
Total CCA customer rate	**$104.6**	**$109.7**	**$110.9**	**$112.4**	**$114.4**	**$117.1**	**$120.4**	**$123.9**	**$127.3**	**$131.1**
PG&E average gen rate for CCA load, $/MWh	**$134.2**	**$144.0**	**$146.7**	**$151.0**	**$155.7**	**$160.8**	**$165.0**	**$170.5**	**$176.0**	**$182.5**
Reserve Fund Adjustment										
Target	$55,074,627	$58,588,575	$60,636,353	$62,532,535	$64,467,115	$66,595,046	$68,748,982	$70,974,528	$73,217,475	$75,690,015
Reserve Fund Adjustment										
Potential Reserve potential	$110,201,860	$128,194,145	$134,215,487	$145,270,805	$156,288,619	$165,801,447	$169,687,264	$178,229,235	$186,523,044	$197,789,460
Potential Reserve additions	$3,139,049	$3,513,948	$2,047,778	$1,896,182	$1,934,580	$2,127,931	$2,153,936	$2,225,546	$2,242,947	$2,472,540
Subtractions from reserve fund	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reserve fund total	**$55,074,627**	**$58,588,575**	**$60,636,353**	**$62,532,535**	**$64,467,115**	**$66,595,046**	**$68,748,982**	**$70,974,528**	**$73,217,475**	**$75,690,015**
Contra Costa CCA Customer Charges, $/MWh (with Reserve Fund Adjustment)										
Rate adjustment from Reserve Fund	$0.8	$0.9	$0.5	$0.5	$0.5	$0.6	$0.6	$0.6	$0.6	$0.6
Average Contra Costa CCA rate	$99.5	$105.5	$108.4	$111.3	$114.3	$117.7	$121.0	$124.5	$127.9	$131.8
PG&E average exit fees for CCA load	$6.0	$5.1	$3.1	$1.7	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0
Total CCA customer rate	**$105.5**	**$110.6**	**$111.5**	**$112.9**	**$114.9**	**$117.7**	**$121.0**	**$124.5**	**$127.9**	**$131.8**
Contra Costa CCA CO2 emissions										
Emissions (Tonnes/MWh)	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Total emissions (Tonnes)	196,074	197,642	162,803	163,997	165,333	166,460	167,595	168,634	170,197	171,328

Note: Reserve fund revenue is used to reduce CCA rates if (i) CCA rates are lower than PG&E rates or (ii) the reserve fund reaches the ceiling of half a year of expenses.

Scenario 2

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Expenses																					
Cost of Power (including losses)	$75,667,208	$155,562,573	$244,603,605	$253,936,224	$262,178,133	$270,821,465	$279,147,605	$288,420,808	$302,569,437	$318,621,199	$336,840,252	$356,586,893	$378,456,407	$388,844,347	$399,378,659	$410,314,502	$421,560,027	$432,993,327	$444,699,721	$456,541,793	$469,291,025
O&M/A&G Costs	$9,081,989	$11,047,477	$14,037,456	$14,312,982	$14,596,957	$14,871,929	$15,146,845	$15,425,482	$15,722,408	$16,025,074	$16,333,641	$16,648,197	$16,968,859	$17,295,746	$17,628,978	$17,968,678	$18,314,999	$18,668,042	$19,027,938	$19,394,819	$19,768,820
Energy Efficiency Programming Costs																					
Total Expenses	**$84,749,197**	**$166,610,049**	**$258,641,061**	**$268,249,207**	**$276,775,090**	**$285,693,394**	**$294,294,450**	**$303,846,289**	**$318,291,846**	**$334,646,273**	**$353,173,892**	**$373,235,090**	**$395,425,266**	**$406,140,093**	**$417,007,637**	**$428,283,180**	**$439,875,026**	**$451,661,369**	**$463,727,659**	**$475,936,612**	**$489,059,845**
Debt Service	**$0**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Total Revenue Requirement	**$84,749,197**	**$172,099,056**	**$264,130,067**	**$273,738,213**	**$282,264,096**	**$291,182,400**	**$294,294,450**	**$303,846,289**	**$318,291,846**	**$334,646,273**	**$353,173,892**	**$373,235,090**	**$395,425,266**	**$406,140,093**	**$417,007,637**	**$428,283,180**	**$439,875,026**	**$451,661,369**	**$463,727,659**	**$475,936,612**	**$489,059,845**
Total Load, MWh	**1,177,121**	**2,366,944**	**3,607,181**	**3,623,598**	**3,641,698**	**3,652,169**	**3,659,921**	**3,666,956**	**3,680,582**	**3,694,258**	**3,707,985**	**3,721,763**	**3,735,593**	**3,749,473**	**3,763,406**	**3,777,390**	**3,791,426**	**3,805,514**	**3,819,655**	**3,833,848**	**3,848,093**
Contra Costa CCA Customer Charges, $/MWh (before Reserve Fund Adjustment)																					
Average Contra Costa CCA generation	$72.0	$72.7	$73.2	$75.5	$77.5	$79.7	$80.4	$82.9	$86.5	$90.6	$95.2	$100.3	$105.9	$108.3	$110.8	$113.4	$116.0	$118.7	$121.4	$124.1	$127.1
PG&E average exit fees for CCA load	$23.7	$19.1	$22.9	$16.6	$16.6	$15.7	$14.6	$12.6	$9.1	$8.0	$7.0	$6.0	$5.1	$3.1	$1.7	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0
Total CCA customer rate	**$95.7**	**$91.8**	**$96.1**	**$92.1**	**$94.1**	**$95.4**	**$95.0**	**$95.5**	**$95.6**	**$98.5**	**$102.2**	**$106.2**	**$111.0**	**$111.4**	**$112.5**	**$114.0**	**$116.0**	**$118.7**	**$121.4**	**$124.1**	**$127.1**
PG&E average gen rate for CCA load, $/MWh	**$101.5**	**$105.7**	**$106.6**	**$112.7**	**$115.5**	**$113.8**	**$113.3**	**$109.2**	**$113.2**	**$119.2**	**$126.3**	**$134.2**	**$144.0**	**$146.7**	**$151.0**	**$155.7**	**$160.8**	**$165.0**	**$170.5**	**$176.0**	**$182.5**
Reserve Fund Adjustment																					
Target	$12,712,380	$25,814,858	$39,619,510	$41,060,732	$42,339,614	$43,677,360	$44,144,167	$45,576,943	$47,743,777	$50,196,941	$52,976,084	$55,985,264	$59,313,790	$60,921,014	$62,551,146	$64,242,477	$65,981,254	$67,749,205	$69,559,149	$71,390,492	$73,358,977
Reserve Fund Adjustment																					
Potential Reserve potential	$6,866,063	$32,879,835	$38,027,080	$74,548,670	$78,053,677	$67,255,940	$67,112,296	$50,168,239	$64,775,682	$76,346,136	$89,284,946	$104,130,951	$123,359,382	$132,317,748	$145,146,736	$157,786,207	$169,893,397	$176,352,443	$187,665,096	$198,702,934	$213,329,715
Potential Reserve additions	$6,866,063	$18,948,796	$13,804,652	$1,441,222	$1,278,883	$1,337,746	$466,807	$1,432,776	$2,166,833	$2,453,164	$2,779,143	$3,009,180	$3,328,526	$1,607,224	$1,630,132	$1,691,331	$1,738,777	$1,767,951	$1,809,944	$1,831,343	$1,968,485
Subtractions from reserve fund	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reserve fund total	**$6,866,063**	**$25,814,858**	**$39,619,510**	**$41,060,732**	**$42,339,614**	**$43,677,360**	**$44,144,167**	**$45,576,943**	**$47,743,777**	**$50,196,941**	**$52,976,084**	**$55,985,264**	**$59,313,790**	**$60,921,014**	**$62,551,146**	**$64,242,477**	**$65,981,254**	**$67,749,205**	**$69,559,149**	**$71,390,492**	**$73,358,977**
Contra Costa CCA Customer Charges, $/MWh (with Reserve Fund Adjustment)																					
Rate adjustment from Reserve Fund	$5.8	$8.0	$3.8	$0.4	$0.4	$0.4	$0.1	$0.4	$0.6	$0.7	$0.7	$0.8	$0.9	$0.4	$0.4	$0.4	$0.5	$0.5	$0.5	$0.5	$0.5
Average Contra Costa CCA rate	$77.8	$80.7	$77.1	$75.9	$77.9	$80.1	$80.5	$83.3	$87.1	$91.2	$96.0	$101.1	$106.7	$108.7	$111.2	$113.8	$116.5	$119.2	$121.9	$124.6	$127.6
PG&E average exit fees for CCA load	$23.7	$19.1	$22.9	$16.6	$16.6	$15.7	$14.6	$12.6	$9.1	$8.0	$7.0	$6.0	$5.1	$3.1	$1.7	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0
Total CCA customer rate	**$101.5**	**$99.8**	**$99.9**	**$92.5**	**$94.4**	**$95.8**	**$95.1**	**$95.9**	**$96.1**	**$99.2**	**$103.0**	**$107.1**	**$111.9**	**$111.9**	**$112.9**	**$114.4**	**$116.5**	**$119.2**	**$121.9**	**$124.6**	**$127.6**
Note: Reserve fund revenue is used to reduce CCA rates if (i) CCA rates are lower than PG&E rates or (ii) the reserve fund reaches the ceiling of half a year of expenses.																					
Contra Costa CCA CO2 emissions																					
Emissions (Tonnes/MWh)	0.04	0.03	0.02	0.02	0.02	0.02	0.02	0.04	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Total emissions (Tonnes)	48,104	76,449	70,394	71,051	71,298	72,351	73,983	158,002	195,517	194,741	179,036	161,586	144,182	144,830	145,465	146,223	146,793	147,369	147,857	148,803	149,369

Scenario 3

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Expenses																					
Cost of Power (including losses)	$74,421,602	$155,059,529	$248,051,939	$262,405,554	$275,771,462	$289,759,015	$303,955,349	$316,069,786	$337,813,788	$362,649,650	$383,978,224	$406,604,081	$431,423,912	$446,808,176	$461,156,092	$475,748,288	$489,543,148	$503,482,983	$517,889,434	$532,382,737	$548,417,000
O&MA&G Costs	$9,081,989	$11,047,477	$14,037,456	$14,312,982	$14,596,957	$14,871,929	$15,146,845	$15,425,482	$15,722,408	$16,025,074	$16,333,641	$16,648,197	$16,968,859	$17,295,746	$17,628,978	$17,968,678	$18,314,999	$18,668,042	$19,027,938	$19,394,819	$19,768,820
Energy Efficiency Programming Costs																					
Total Expenses	**$83,503,591**	**$166,107,006**	**$262,089,395**	**$276,718,537**	**$290,368,419**	**$304,630,945**	**$319,102,194**	**$331,495,267**	**$353,536,197**	**$378,674,724**	**$400,311,865**	**$423,252,278**	**$448,392,771**	**$464,103,921**	**$478,785,070**	**$493,716,965**	**$507,858,147**	**$522,151,025**	**$536,917,372**	**$551,777,556**	**$568,185,821**
Debt Service	**$0**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Total Revenue Requirement	**$83,503,591**	**$171,596,012**	**$267,578,402**	**$282,207,543**	**$295,857,426**	**$310,119,951**	**$319,102,194**	**$331,495,267**	**$353,536,197**	**$378,674,724**	**$400,311,865**	**$423,252,278**	**$448,392,771**	**$464,103,921**	**$478,785,070**	**$493,716,965**	**$507,858,147**	**$522,151,025**	**$536,917,372**	**$551,777,556**	**$568,185,821**
Total Load, MWh	**1,177,121**	**2,366,944**	**3,607,181**	**3,623,598**	**3,641,698**	**3,652,169**	**3,659,921**	**3,666,956**	**3,680,582**	**3,694,258**	**3,707,985**	**3,721,763**	**3,735,593**	**3,749,473**	**3,763,406**	**3,777,390**	**3,791,426**	**3,805,514**	**3,819,655**	**3,833,848**	**3,848,093**
Alameda CCA Customer Charges, $/MWh (before Reserve Fund Adjustment)																					
Average Alameda CCA generation	$70.9	$72.5	$74.2	$77.9	$81.2	$84.9	$87.2	$90.4	$96.1	$102.5	$108.0	$113.7	$120.0	$123.8	$127.2	$130.7	$133.9	$137.2	$140.6	$143.9	$147.7
PG&E average exit fees for CCA load	$23.7	$19.1	$22.9	$16.6	$16.6	$15.7	$14.6	$12.6	$9.1	$8.0	$7.0	$6.0	$5.1	$3.1	$1.7	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0
Total CCA customer rate	**$94.6**	**$91.6**	**$97.0**	**$94.4**	**$97.8**	**$100.6**	**$101.8**	**$103.0**	**$105.1**	**$110.5**	**$115.0**	**$119.7**	**$125.1**	**$126.9**	**$128.9**	**$131.3**	**$133.9**	**$137.2**	**$140.6**	**$143.9**	**$147.7**
PG&E average gen rate for CCA load, $/MWh	**$101.5**	**$105.7**	**$106.6**	**$112.7**	**$115.5**	**$113.8**	**$113.3**	**$109.2**	**$113.2**	**$119.2**	**$126.3**	**$134.2**	**$144.0**	**$146.7**	**$151.0**	**$155.7**	**$160.8**	**$165.0**	**$170.5**	**$176.0**	**$182.5**
Reserve Fund Adjustment																					
Target	$12,525,539	$25,739,402	$40,136,760	$42,331,131	$44,378,614	$46,517,993	$47,865,329	$49,724,290	$53,030,429	$56,801,209	$60,046,780	$63,487,842	$67,258,916	$69,615,588	$71,817,760	$74,057,545	$76,178,722	$78,322,654	$80,537,606	$82,766,633	$85,227,873
Reserve Fund Adjustment																					
Potential Reserve potential	$8,111,669	$33,382,879	$34,578,745	$66,079,340	$64,460,347	$48,318,389	$42,304,552	$22,519,261	$29,531,331	$32,317,684	$42,146,974	$54,113,763	$70,391,877	$74,353,919	$83,369,303	$92,352,422	$101,910,276	$105,862,787	$114,475,383	$122,861,990	$134,203,739
Potential Reserve additions	$8,111,669	$17,627,733	$14,397,358	$2,194,371	$2,047,482	$2,139,379	$1,347,336	$1,858,961	$3,306,139	$3,770,779	$3,245,571	$3,441,062	$3,771,074	$2,356,673	$2,202,172	$2,239,784	$2,121,177	$2,143,932	$2,214,952	$2,229,028	$2,461,240
Subtractions from reserve fund	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reserve fund total	**$8,111,669**	**$25,739,402**	**$40,136,760**	**$42,331,131**	**$44,378,614**	**$46,517,993**	**$47,865,329**	**$49,724,290**	**$53,030,429**	**$56,801,209**	**$60,046,780**	**$63,487,842**	**$67,258,916**	**$69,615,588**	**$71,817,760**	**$74,057,545**	**$76,178,722**	**$78,322,654**	**$80,537,606**	**$82,766,633**	**$85,227,873**
Alameda CCA Customer Charges, $/MWh (with Reserve Fund Adjustment)																					
Rate adjustment from Reserve Fund	$6.9	$7.4	$4.0	$0.6	$0.6	$0.6	$0.4	$0.5	$0.9	$1.0	$0.9	$0.9	$1.0	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6
Average Alameda CCA rate	$77.8	$79.9	$78.2	$78.5	$81.8	$85.5	$87.6	$90.9	$97.0	$103.5	$108.8	$114.6	$121.0	$124.4	$127.8	$131.3	$134.5	$137.8	$141.1	$144.5	$148.3
PG&E average exit fees for CCA load	$23.7	$19.1	$22.9	$16.6	$16.6	$15.7	$14.6	$12.6	$9.1	$8.0	$7.0	$6.0	$5.1	$3.1	$1.7	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0
Total CCA customer rate	**$101.5**	**$99.0**	**$101.0**	**$95.0**	**$98.4**	**$101.2**	**$102.1**	**$103.5**	**$106.0**	**$111.5**	**$115.8**	**$120.6**	**$126.2**	**$127.5**	**$129.5**	**$131.9**	**$134.5**	**$137.8**	**$141.1**	**$144.5**	**$148.3**
Note: Reserve fund revenue is used to reduce CCA rates if (i) CCA rates are lower than PG&E rates or (ii) the reserve fund reaches the ceiling of half a year of expenses.																					
Alameda CCA CO2 emissions																					
Emissions (Tonnes/MWh)	0.04	0.03	0.02	0.02	0.02	0.02	0.02	0.04	0.05	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Total emissions (Tonnes)	48,104	76,449	70,394	71,051	71,298	72,351	73,983	158,002	195,517	194,741	195,332	196,074	197,642	162,803	163,997	165,333	166,460	167,595	168,634	170,197	171,328

Scenario 4

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Expenses																					
Cost of Power (including losses)	$77,332,918	$162,719,907	$262,070,819	$279,609,557	$297,052,506	$315,993,039	$336,528,138	$362,105,625	$391,911,928	$427,041,105	$449,571,955	$473,571,311	$500,641,660	$511,836,324	$523,149,117	$534,898,122	$546,971,922	$559,212,625	$571,745,163	$584,386,818	$598,049,458
O&M/A&G Costs	$9,081,989	$11,047,477	$14,037,456	$14,312,982	$14,596,957	$14,871,929	$15,146,845	$15,425,482	$15,722,408	$16,025,074	$16,333,641	$16,648,197	$16,968,859	$17,295,746	$17,628,978	$17,968,678	$18,314,999	$18,668,042	$19,027,938	$19,394,819	$19,768,820
Energy Efficiency Programming Costs																					
Total Expenses	**$86,414,907**	**$173,767,384**	**$276,108,275**	**$293,922,540**	**$311,649,463**	**$330,864,968**	**$351,674,983**	**$377,531,107**	**$407,634,337**	**$443,066,180**	**$465,905,596**	**$490,219,508**	**$517,610,519**	**$529,132,070**	**$540,778,094**	**$552,866,799**	**$565,286,921**	**$577,880,667**	**$590,773,101**	**$603,781,637**	**$617,818,279**
Debt Service	**$0**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$5,489,006**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Total Revenue Requirement	**$86,414,907**	**$179,256,390**	**$281,597,282**	**$299,411,546**	**$317,138,469**	**$336,353,975**	**$351,674,983**	**$377,531,107**	**$407,634,337**	**$443,066,180**	**$465,905,596**	**$490,219,508**	**$517,610,519**	**$529,132,070**	**$540,778,094**	**$552,866,799**	**$565,286,921**	**$577,880,667**	**$590,773,101**	**$603,781,637**	**$617,818,279**
Total Load, MWh	**1,177,121**	**2,366,944**	**3,607,181**	**3,623,598**	**3,641,698**	**3,652,169**	**3,659,921**	**3,666,956**	**3,680,582**	**3,694,258**	**3,707,985**	**3,721,763**	**3,735,593**	**3,749,473**	**3,763,406**	**3,777,390**	**3,791,426**	**3,805,514**	**3,819,655**	**3,833,848**	**3,848,093**
Alameda CCA Customer Charges, $/MWh (before Reserve Fund Adjustment)																					
Average Alameda CCA generation	$73.4	$75.7	$78.1	$82.6	$87.1	$92.1	$96.1	$103.0	$110.8	$119.9	$125.6	$131.7	$138.6	$141.1	$143.7	$146.4	$149.1	$151.9	$154.7	$157.5	$160.6
PG&E average exit fees for CCA load	$23.7	$19.1	$22.9	$16.6	$16.6	$15.7	$14.6	$12.6	$9.1	$8.0	$7.0	$6.0	$5.1	$3.1	$1.7	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0
Total CCA customer rate	**$97.1**	**$94.8**	**$100.9**	**$99.2**	**$103.7**	**$107.8**	**$110.7**	**$115.6**	**$119.8**	**$127.9**	**$132.7**	**$137.7**	**$143.7**	**$144.2**	**$145.4**	**$147.0**	**$149.1**	**$151.9**	**$154.7**	**$157.5**	**$160.6**
PG&E average gen rate for CCA load, $/MWh	**$101.5**	**$105.7**	**$106.6**	**$112.7**	**$115.5**	**$113.8**	**$113.3**	**$109.2**	**$113.2**	**$119.2**	**$126.3**	**$134.2**	**$144.0**	**$146.7**	**$151.0**	**$155.7**	**$160.8**	**$165.0**	**$170.5**	**$176.0**	**$182.5**
Reserve Fund Adjustment																					
Target	$12,962,236	$26,888,459	$42,239,592	$44,911,732	$47,570,770	$50,453,096	$52,751,248	$56,629,666	$61,145,150	$66,459,927	$69,885,839	$73,532,926	$77,641,578	$79,369,810	$81,116,714	$82,930,020	$84,793,038	$86,682,100	$88,615,965	$90,567,246	$92,672,742
Reserve Fund Adjustment																					
Potential Reserve potential	$5,200,352	$25,722,501	$20,559,865	$48,875,337	$43,179,304	$22,084,365	$9,731,762	$0	$0	$0	$0	$0	$1,174,129	$9,325,771	$21,376,279	$33,202,588	$44,481,502	$50,133,145	$60,619,654	$70,857,909	$84,571,282
Potential Reserve additions	$5,200,352	$21,688,106	$15,351,134	$2,672,140	$2,659,039	$2,882,326	$2,298,151	$0	$0	$0	$0	$0	$77,641,578	$1,728,233	$1,746,904	$1,813,306	$1,863,018	$1,889,062	$1,933,865	$1,951,280	$2,105,496
Subtractions from reserve fund	$0	$0	$0	$0	$0	$0	$0	$23,516,579	$24,566,809	$4,667,860	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Reserve fund total	**$5,200,352**	**$26,888,459**	**$42,239,592**	**$44,911,732**	**$47,570,770**	**$50,453,096**	**$52,751,248**	**$29,234,669**	**$4,667,860**	**$0**	**$0**	**$0**	**$77,641,578**	**$79,369,810**	**$81,116,714**	**$82,930,020**	**$84,793,038**	**$86,682,100**	**$88,615,965**	**$90,567,246**	**$92,672,742**
Alameda CCA Customer Charges, $/MWh (with Reserve Fund Adjustment)																					
Rate adjustment from Reserve Fund	$4.4	$9.2	$4.3	$0.7	$0.7	$0.8	$0.6	-$6.4	-$6.7	-$1.3	$0.0	$0.0	$20.8	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
Average Alameda CCA rate	$77.8	$84.9	$82.3	$83.4	$87.8	$92.9	$96.7	$96.5	$104.1	$118.7	$125.6	$131.7	$159.3	$141.6	$144.2	$146.8	$149.6	$152.3	$155.2	$158.0	$161.1
PG&E average exit fees for CCA load	$23.7	$19.1	$22.9	$16.6	$16.6	$15.7	$14.6	$12.6	$9.1	$8.0	$7.0	$6.0	$5.1	$3.1	$1.7	$0.6	$0.0	$0.0	$0.0	$0.0	$0.0
Total CCA customer rate	**$101.5**	**$104.0**	**$105.2**	**$99.9**	**$104.4**	**$108.6**	**$111.3**	**$109.2**	**$113.2**	**$126.6**	**$132.7**	**$137.7**	**$164.5**	**$144.7**	**$145.8**	**$147.4**	**$149.6**	**$152.3**	**$155.2**	**$158.0**	**$161.1**
Note: Reserve fund revenue is used to reduce CCA rates if (i) CCA rates are lower than PG&E rates or (ii) the reserve fund reaches the ceiling of half a year of expenses.																					
Alameda CCA CO2 emissions																					
Emissions (Tonnes/MWh)	0.04	0.03	0.02	0.02	0.02	0.02	0.02	0.04	0.05	0.05	0.05	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Total emissions (Tonnes)	48,104	76,449	70,394	71,051	71,298	72,351	73,983	158,002	195,517	194,741	179,036	161,586	144,182	144,830	145,465	146,223	146,793	147,369	147,857	148,803	149,369

Appendix H. MCE's Joint Powers Agreements

Marin Energy Authority
- Joint Powers Agreement -

Effective December 19, 2008
As amended by Amendment No. 1 dated December 3, 2009
As further amended by Amendment No. 2 dated March 4, 2010
As further amended by Amendment No. 3 dated May 6, 2010
As further amended by Amendment No. 4 dated December 1, 2011
As further amended by Amendment No. 5 dated July 5, 2012
As further amended by Amendment No. 6 dated September 5, 2013
As further amended by Amendment No. 7 dated December 5, 2013
As further amended by Amendment No. 8 dated September 4, 2014
As further amended by Amendment No. 9 dated December 4, 2014
As further amended by Amendment No. 10 dated April 21, 2016

Among The Following Parties:
City of American Canyon
City of Belvedere
City of Benicia
City of Calistoga
Town of Corte Madera
City of El Cerrito
Town of Fairfax
City of Lafayette
City of Larkspur
City of Mill Valley
City of Napa
City of Novato
City of Richmond
Town of Ross
Town of San Anselmo
City of San Pablo
City of San Rafael
City of Sausalito
City of St. Helena
Town of Tiburon
City of Walnut Creek
Town of Yountville
County of Marin
County of Napa

MARIN ENERGY AUTHORITY
JOINT POWERS AGREEMENT

This **Joint Powers Agreement** ("Agreement"), effective as of December 19, 2008, is made and entered into pursuant to the provisions of Title 1, Division 7, Chapter 5, Article 1 (Section 6500 et seq.) of the California Government Code relating to the joint exercise of powers among the parties set forth in Exhibit B ("Parties"). The term "Parties" shall also include an incorporated municipality or county added to this Agreement in accordance with Section 3.1.

RECITALS

1. The Parties are either incorporated municipalities or counties sharing various powers under California law, including but not limited to the power to purchase, supply, and aggregate electricity for themselves and their inhabitants.

2. In 2006, the State Legislature adopted AB 32, the Global Warming Solutions Act, which mandates a reduction in greenhouse gas emissions in 2020 to 1990 levels. The California Air Resources Board is promulgating regulations to implement AB 32 which will require local government to develop programs to reduce greenhouse emissions.

3. The purposes for the Initial Participants (as such term is defined in Section 2.2 below) entering into this Agreement include addressing climate change by reducing energy related greenhouse gas emissions and securing energy supply and price stability, energy efficiencies and local economic benefits. It is the intent of this Agreement to promote the development and use of a wide range of renewable energy sources and energy efficiency programs, including but not limited to solar and wind energy production.

4. The Parties desire to establish a separate public agency, known as the Marin Energy Authority ("Authority"), under the provisions of the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 et seq.) ("Act") in order to collectively study, promote, develop, conduct, operate, and manage energy programs.

5. The Initial Participants have each adopted an ordinance electing to implement through the Authority Community Choice Aggregation, an electric service enterprise agency available to cities and counties pursuant to California Public Utilities Code Section 366.2 ("CCA Program"). The first priority of the Authority will be the consideration of those actions necessary to implement the CCA Program. Regardless of whether or not Program Agreement 1 is approved and the CCA Program becomes operational, the parties intend for the Authority to continue to study, promote, develop, conduct, operate and manage other energy programs.

AGREEMENT

NOW, THEREFORE, in consideration of the mutual promises, covenants, and conditions hereinafter set forth, it is agreed by and among the Parties as follows:

ARTICLE 1
CONTRACT DOCUMENTS

1.1 **Definitions**. Capitalized terms used in the Agreement shall have the meanings specified in Exhibit A, unless the context requires otherwise.

1.2 **Documents Included**. This Agreement consists of this document and the following exhibits, all of which are hereby incorporated into this Agreement.

Exhibit A:	Definitions
Exhibit B:	List of the Parties
Exhibit C:	Annual Energy Use
Exhibit D:	Voting Shares

1.3 **Revision of Exhibits**. The Parties agree that Exhibits B, C and D to this Agreement describe certain administrative matters that may be revised upon the approval of the Board, without such revision constituting an amendment to this Agreement, as described in Section 8.4. The Authority shall provide written notice to the Parties of the revision of any such exhibit.

ARTICLE 2
FORMATION OF MARIN ENERGY AUTHORITY

2.1 **Effective Date and Term**. This Agreement shall become effective and Marin Energy Authority shall exist as a separate public agency on the date this Agreement is executed by at least two Initial Participants after the adoption of the ordinances required by Public Utilities Code Section 366.2(c)(10). The Authority shall provide notice to the Parties of the Effective Date. The Authority shall continue to exist, and this Agreement shall be effective, until this Agreement is terminated in accordance with Section 7.4, subject to the rights of the Parties to withdraw from the Authority.

2.2 **Initial Participants**. During the first 180 days after the Effective Date, all other Initial Participants may become a Party by executing this Agreement and delivering an executed copy of this Agreement and a copy of the adopted ordinance required by Public Utilities Code Section 366.2(c)(10) to the Authority. Additional conditions, described in Section 3.1, may apply (i) to either an incorporated municipality or county desiring to become a Party and is not an Initial Participant and (ii) to Initial Participants that have not executed and delivered this Agreement within the time period described above.

2.3 **<u>Formation</u>**. There is formed as of the Effective Date a public agency named the Marin Energy Authority. Pursuant to Sections 6506 and 6507 of the Act, the Authority is a public agency separate from the Parties. The debts, liabilities or obligations of the Authority shall not be debts, liabilities or obligations of the individual Parties unless the governing board of a Party agrees in writing to assume any of the debts, liabilities or obligations of the Authority. A Party who has not agreed to assume an Authority debt, liability or obligation shall not be responsible in any way for such debt, liability or obligation even if a majority of the Parties agree to assume the debt, liability or obligation of the Authority. Notwithstanding Section 8.4 of this Agreement, this Section 2.3 may not be amended unless such amendment is approved by the governing board of each Party.

2.4 **<u>Purpose</u>**. The purpose of this Agreement is to establish an independent public agency in order to exercise powers common to each Party to study, promote, develop, conduct, operate, and manage energy and energy-related climate change programs, and to exercise all other powers necessary and incidental to accomplishing this purpose. Without limiting the generality of the foregoing, the Parties intend for this Agreement to be used as a contractual mechanism by which the Parties are authorized to participate as a group in the CCA Program, as further described in Section 5.1. The Parties intend that subsequent agreements shall define the terms and conditions associated with the actual implementation of the CCA Program and any other energy programs approved by the Authority.

2.5 **<u>Powers</u>**. The Authority shall have all powers common to the Parties and such additional powers accorded to it by law. The Authority is authorized, in its own name, to exercise all powers and do all acts necessary and proper to carry out the provisions of this Agreement and fulfill its purposes, including, but not limited to, each of the following:

2.5.1 make and enter into contracts;
2.5.2 employ agents and employees, including but not limited to an Executive Director;
2.5.3 acquire, contract, manage, maintain, and operate any buildings, works or improvements;
2.5.4 acquire by eminent domain, or otherwise, except as limited under Section 6508 of the Act, and to hold or dispose of any property;
2.5.5 lease any property;
2.5.6 sue and be sued in its own name;
2.5.7 incur debts, liabilities, and obligations, including but not limited to loans from private lending sources pursuant to its temporary borrowing powers such as Government Code Section 53850 et seq. and authority under the Act;
2.5.8 issue revenue bonds and other forms of indebtedness;
2.5.9 apply for, accept, and receive all licenses, permits, grants, loans or other aids from any federal, state or local public agency;

2.5.10 submit documentation and notices, register, and comply with orders, tariffs and agreements for the establishment and implementation of the CCA Program and other energy programs;

2.5.11 adopt rules, regulations, policies, bylaws and procedures governing the operation of the Authority ("Operating Rules and Regulations"); and

2.5.12 make and enter into service agreements relating to the provision of services necessary to plan, implement, operate and administer the CCA Program and other energy programs, including the acquisition of electric power supply and the provision of retail and regulatory support services.

2.6 **<u>Limitation on Powers</u>**. As required by Government Code Section 6509, the power of the Authority is subject to the restrictions upon the manner of exercising power possessed by the County of Marin.

2.7 **<u>Compliance with Local Zoning and Building Laws</u>**. Notwithstanding any other provisions of this Agreement or state law, any facilities, buildings or structures located, constructed or caused to be constructed by the Authority within the territory of the Authority shall comply with the General Plan, zoning and building laws of the local jurisdiction within which the facilities, buildings or structures are constructed.

ARTICLE 3
AUTHORITY PARTICIPATION

3.1 **<u>Addition of Parties</u>**. Subject to Section 2.2, relating to certain rights of Initial Participants, other incorporated municipalities and counties may become Parties upon (a) the adoption of a resolution by the governing body of such incorporated municipality or such county requesting that the incorporated municipality or county, as the case may be, become a member of the Authority, (b) the adoption, by an affirmative vote of the Board satisfying the requirements described in Section 4.9.1, of a resolution authorizing membership of the additional incorporated municipality or county, specifying the membership payment, if any, to be made by the additional incorporated municipality or county to reflect its pro rata share of organizational, planning and other pre-existing expenditures, and describing additional conditions, if any, associated with membership, (c) the adoption of an ordinance required by Public Utilities Code Section 366.2(c)(10) and execution of this Agreement and other necessary program agreements by the incorporated municipality or county, (d) payment of the membership payment, if any, and (e) satisfaction of any conditions established by the Board. Notwithstanding the foregoing, in the event the Authority decides to not implement a CCA Program, the requirement that an additional party adopt the ordinance required by Public Utilities Code Section 366.2(c)(10) shall not apply. Under such circumstance, the Board resolution authorizing membership of an additional incorporated municipality or county shall be adopted in accordance with the voting requirements of Section 4.10.

3.2 **Continuing Participation**. The Parties acknowledge that membership in the Authority may change by the addition and/or withdrawal or termination of Parties. The Parties agree to participate with such other Parties as may later be added, as described in Section 3.1. The Parties also agree that the withdrawal or termination of a Party shall not affect this Agreement or the remaining Parties' continuing obligations under this Agreement.

ARTICLE 4
GOVERNANCE AND INTERNAL ORGANIZATION

4.1 **Board of Directors**. The governing body of the Authority shall be a Board of Directors ("Board") consisting of one director for each Party appointed in accordance with Section 4.2.

4.2 **Appointment and Removal of Directors**. The Directors shall be appointed and may be removed as follows:

4.2.1 The governing body of each Party shall appoint and designate in writing one regular Director who shall be authorized to act for and on behalf of the Party on matters within the powers of the Authority. The governing body of each Party also shall appoint and designate in writing one alternate Director who may vote on matters when the regular Director is absent from a Board meeting. The person appointed and designated as the Director or the alternate Director shall be a member of the governing body of the Party.

4.2.2 The Operating Rules and Regulations, to be developed and approved by the Board in accordance with Section 2.5.11, shall specify the reasons for and process associated with the removal of an individual Director for cause. Notwithstanding the foregoing, no Party shall be deprived of its right to seat a Director on the Board and any such Party for which its Director and/or alternate Director has been removed may appoint a replacement.

4.3 **Terms of Office**. Each Director shall serve at the pleasure of the governing body of the Party that the Director represents, and may be removed as Director by such governing body at any time. If at any time a vacancy occurs on the Board, a replacement shall be appointed to fill the position of the previous Director in accordance with the provisions of Section 4.2 within 90 days of the date that such position becomes vacant.

4.4 **Quorum**. A majority of the Directors shall constitute a quorum, except that less than a quorum may adjourn from time to time in accordance with law.

4.5 **Powers and Function of the Board**. The Board shall conduct or authorize to be conducted all business and activities of the Authority, consistent with this Agreement, the Authority Documents, the Operating Rules and Regulations, and applicable law.

4.6 **Executive Committee**. The Board may establish an executive committee consisting of a smaller number of Directors. The Board may delegate to the executive committee such authority as the Board might otherwise exercise, subject to limitations placed on the Board's authority to delegate certain essential functions, as described in the Operating Rules and Regulations. The Board may not delegate to the Executive Committee or any other committee its authority under Section 2.5.11 to adopt and amend the Operating Rules and Regulations.

4.7 **Commissions, Boards and Committees**. The Board may establish any advisory commissions, boards and committees as the Board deems appropriate to assist the Board in carrying out its functions and implementing the CCA Program, other energy programs and the provisions of this Agreement.

4.8 **Director Compensation**. Compensation for work performed by Directors on behalf of the Authority shall be borne by the Party that appointed the Director. The Board, however, may adopt by resolution a policy relating to the reimbursement of expenses incurred by Directors.

4.9 **Board Voting Related to the CCA Program**.

4.9.1. To be effective, on all matters specifically related to the CCA Program, a vote of the Board shall consist of the following: (1) a majority of all Directors shall vote in the affirmative or such higher voting percentage expressly set forth in Sections 7.2 and 8.4 (the "percentage vote") and (2) the corresponding voting shares (as described in Section 4.9.2 and Exhibit D) of all such Directors voting in the affirmative shall exceed 50%, or such other higher voting shares percentage expressly set forth in Sections 7.2 and 8.4 (the "percentage voting shares"), provided that, in instances in which such other higher voting share percentage would result in any one Director having a voting share that equals or exceeds that which is necessary to disapprove the matter being voted on by the Board, at least one other Director shall be required to vote in the negative in order to disapprove such matter.

4.9.2. Unless otherwise stated herein, voting shares of the Directors shall be determined by combining the following: (1) an equal voting share for each Director determined in accordance with the formula detailed in Section 4.9.2.1, below; and (2) an additional voting share determined in accordance with the formula detailed in Section 4.9.2.2, below.

4.9.2.1 Pro Rata Voting Share. Each Director shall have an equal voting share as determined by the following formula: (1/total number of

Directors) multiplied by 50, and

4.9.2.2 Annual Energy Use Voting Share. Each Director shall have an additional voting share as determined by the following formula: (Annual Energy Use/Total Annual Energy) multiplied by 50, where (a) "Annual Energy Use" means, (i) with respect to the first 5 years following the Effective Date, the annual electricity usage, expressed in kilowatt hours ("kWhs"), within the Party's respective jurisdiction and (ii) with respect to the period after the fifth anniversary of the Effective Date, the annual electricity usage, expressed in kWhs, of accounts within a Party's respective jurisdiction that are served by the Authority and (b) "Total Annual Energy" means the sum of all Parties' Annual Energy Use. The initial values for Annual Energy use are designated in Exhibit C, and shall be adjusted annually as soon as reasonably practicable after January 1, but no later than March 1 of each year

4.9.2.3 The voting shares are set forth in Exhibit D. Exhibit D may be updated to reflect revised annual energy use amounts and any changes in the parties to the Agreement without amending the Agreement provided that the Board is provided a copy of the updated Exhibit D.

4.10 **Board Voting on General Administrative Matters and Programs Not Involving CCA.** Except as otherwise provided by this Agreement or the Operating Rules and Regulations, each member shall have one vote on general administrative matters, including but not limited to the adoption and amendment of the Operating Rules and Regulations, and energy programs not involving CCA. Action on these items shall be determined by a majority vote of the quorum present and voting on the item or such higher voting percentage expressly set forth in Sections 7.2 and 8.4.

4.11 **Board Voting on CCA Programs Not Involving CCA That Require Financial Contributions.** The approval of any program or other activity not involving CCA that requires financial contributions by individual Parties shall be approved only by a majority vote of the full membership of the Board subject to the right of any Party who votes against the program or activity to opt-out of such program or activity pursuant to this section. The Board shall provide at least 45 days prior written notice to each Party before it considers the program or activity for adoption at a Board meeting. Such notice shall be provided to the governing body and the chief administrative officer, city manager or town manager of each Party. The Board also shall provide written notice of such program or activity adoption to the above-described officials of each Party within 5 days after the Board adopts the program or activity. Any Party voting against the approval of a program or other activity of the Authority requiring financial contributions by individual Parties may elect to opt-out of participation in such program or activity by providing written notice of this election to the Board within 30 days after the program or activity is approved by the Board. Upon timely exercising its opt-out election, a Party shall not have any financial obligation or any liability whatsoever for the conduct or operation of such program or activity.

4.12 **<u>Meetings and Special Meetings of the Board</u>**. The Board shall hold at least four regular meetings per year, but the Board may provide for the holding of regular meetings at more frequent intervals. The date, hour and place of each regular meeting shall be fixed by resolution or ordinance of the Board. Regular meetings may be adjourned to another meeting time. Special meetings of the Board may be called in accordance with the provisions of California Government Code Section 54956. Directors may participate in meetings telephonically, with full voting rights, only to the extent permitted by law. All meetings of the Board shall be conducted in accordance with the provisions of the Ralph M. Brown Act (California Government Code Section 54950 et seq.).

4.13 **<u>Selection of Board Officers</u>.**

4.13.1 **Chair and Vice Chair**. The Directors shall select, from among themselves, a Chair, who shall be the presiding officer of all Board meetings, and a Vice Chair, who shall serve in the absence of the Chair. The term of office of the Chair and Vice Chair shall continue for one year, but there shall be no limit on the number of terms held by either the Chair or Vice Chair. The office of either the Chair or Vice Chair shall be declared vacant and a new selection shall be made if: (a) the person serving dies, resigns, or the Party that the person represents removes the person as its representative on the Board or (b) the Party that he or she represents withdraws form the Authority pursuant to the provisions of this Agreement.

4.13.2 **Secretary**. The Board shall appoint a Secretary, who need not be a member of the Board, who shall be responsible for keeping the minutes of all meetings of the Board and all other official records of the Authority.

4.13.3 **Treasurer and Auditor**. The Board shall appoint a qualified person to act as the Treasurer and a qualified person to act as the Auditor, neither of whom needs to be a member of the Board. If the Board so designates, and in accordance with the provisions of applicable law, a qualified person may hold both the office of Treasurer and the office of Auditor of the Authority. Unless otherwise exempted from such requirement, the Authority shall cause an independent audit to be made by a certified public accountant, or public accountant, in compliance with Section 6505 of the Act. The Treasurer shall act as the depositary of the Authority and have custody of all the money of the Authority, from whatever source, and as such, shall have all of the duties and responsibilities specified in Section 6505.5 of the Act. The Board may require the Treasurer and/or Auditor to file with the Authority an official bond in an amount to be fixed by the Board, and if so requested the Authority shall pay the cost of premiums associated with the bond. The Treasurer shall report directly to the Board and shall comply with the requirements of treasurers of incorporated municipalities. The Board may transfer the responsibilities of Treasurer to any person or entity as the law may provide at the time. The duties and obligations of the Treasurer are further specified in Article 6.

4.14 **<u>Administrative Services Provider</u>.** The Board may appoint one or more administrative services providers to serve as the Authority's agent for planning, implementing, operating and administering the CCA Program, and any other program approved by the Board, in accordance with the provisions of a written agreement between the Authority and the appointed administrative services provider or providers that will be known as an Administrative Services Agreement. The Administrative Services Agreement shall set forth the terms and conditions by which the appointed administrative services provider shall perform or cause to be performed all tasks necessary for planning, implementing, operating and administering the CCA Program and other approved programs. The Administrative Services Agreement shall set forth the term of the Agreement and the circumstances under which the Administrative Services Agreement may be terminated by the Authority. This section shall not in any way be construed to limit the discretion of the Authority to hire its own employees to administer the CCA Program or any other program.

ARTICLE 5
IMPLEMENTATION ACTION AND AUTHORITY DOCUMENTS

5.1 **<u>Preliminary Implementation of the CCA Program.</u>**

5.1.1 **Enabling Ordinance**. Except as otherwise provided by Section 3.1, prior to the execution of this Agreement, each Party shall adopt an ordinance in accordance with Public Utilities Code Section 366.2(c)(10) for the purpose of specifying that the Party intends to implement a CCA Program by and through its participation in the Authority.

5.1.2 **Implementation Plan**. The Authority shall cause to be prepared an Implementation Plan meeting the requirements of Public Utilities Code Section 366.2 and any applicable Public Utilities Commission regulations as soon after the Effective Date as reasonably practicable. The Implementation Plan shall not be filed with the Public Utilities Commission until it is approved by the Board in the manner provided by Section 4.9.

5.1.3 Effect of Vote On Required Implementation Action. In the event that two or more Parties vote to approve Program Agreement 1 or any earlier action required for the implementation of the CCA Program ("Required Implementation Action"), but such vote is insufficient to approve the Required Implementation Action under Section 4.9, the following will occur:

5.1.3.1 The Parties voting against the Required Implementation Action shall no longer be a Party to this Agreement and this Agreement shall be terminated, without further notice, with respect to each of the Parties voting against the Required Implementation Action at the time this vote is final. The Board may take a provisional vote on a Required Implementation Action in order to initially determine the position of the Parties on the Required Implementation Action. A vote, specifically stated in the record of the Board meeting to be a provisional vote, shall not be considered a final vote with the consequences stated above. A Party who is terminated from this Agreement pursuant to this section shall be considered the same as a Party that voluntarily withdrew from the Agreement under Section 7.1.1.1.

5.1.3.2 After the termination of any Parties pursuant to Section 5.1.3.1, the remaining Parties to this Agreement shall be only the Parties who voted in favor of the Required Implementation Action.

5.1.4 Termination of CCA Program. Nothing contained in this Article or this Agreement shall be construed to limit the discretion of the Authority to terminate the implementation or operation of the CCA Program at any time in accordance with any applicable requirements of state law.

5.2 **Authority Documents**. The Parties acknowledge and agree that the affairs of the Authority will be implemented through various documents duly adopted by the Board through Board resolution, including but not necessarily limited to the Operating Rules and Regulations, the annual budget, and specified plans and policies defined as the Authority Documents by this Agreement. The Parties agree to abide by and comply with the terms and conditions of all such Authority Documents that may be adopted by the Board, subject to the Parties' right to withdraw from the Authority as described in Article 7.

ARTICLE 6
FINANCIAL PROVISIONS

6.1 **Fiscal Year**. The Authority's fiscal year shall be 12 months commencing July 1 and ending June 30. The fiscal year may be changed by Board resolution.

6.2 **Depository**.

6.2.1 All funds of the Authority shall be held in separate accounts in the name of the Authority and not commingled with funds of any Party or any other person or entity.

6.2.2 All funds of the Authority shall be strictly and separately accounted for, and regular reports shall be rendered of all receipts and disbursements, at least quarterly during the fiscal year. The books and records of the Authority shall be open to inspection by the Parties at all reasonable times. The Board shall contract with a certified public accountant or public accountant to make an annual audit of the accounts and records of the Authority, which shall be conducted in accordance with the requirements of Section 6505 of the Act.

6.2.3 All expenditures shall be made in accordance with the approved budget and upon the approval of any officer so authorized by the Board in accordance with its Operating Rules and Regulations. The Treasurer shall draw checks or warrants or make payments by other means for claims or disbursements not within an applicable budget only upon the prior approval of the Board.

6.3 **Budget and Recovery Costs**.

6.3.1 **Budget**. The initial budget shall be approved by the Board. The Board may revise the budget from time to time through an Authority Document as may be reasonably necessary to address contingencies and unexpected expenses. All subsequent budgets of the Authority shall be prepared and approved by the Board in accordance with the Operating Rules and Regulations.

6.3.2 **County Funding of Initial Costs**. The County of Marin shall fund the Initial Costs of the Authority in implementing the CCA Program in an amount not to exceed $500,000 unless a larger amount of funding is approved by the Board of Supervisors of the County**.** This funding shall be paid by the County at the times and in the amounts required by the Authority. In the event that the CCA Program becomes operational, these Initial Costs paid by the County of Marin shall be included in the customer charges for electric services as provided by Section 6.3.4 to the extent permitted by law, and the County of Marin shall be reimbursed from the payment of such charges by customers of the Authority. The Authority may establish a reasonable time period over which such costs are recovered. In the event that the CCA Program does not become operational, the County of Marin shall not be entitled to any reimbursement of the Initial Costs it has paid from the Authority or any Party.

6.3.3 **CCA Program Costs**. The Parties desire that, to the extent reasonably practicable, all costs incurred by the Authority that are directly or indirectly attributable to the provision of electric services under the CCA Program, including the establishment and maintenance of various reserve and performance funds, shall be recovered through charges to CCA customers receiving such electric services.

6.3.4 **General Costs**. Costs that are not directly or indirectly attributable to the provision of electric services under the CCA Program, as determined by the Board, shall be defined as general costs. General costs shall be shared among the Parties on such basis as the Board shall determine pursuant to an Authority Document.

6.3.5 **Other Energy Program Costs**. Costs that are directly or indirectly attributable to energy programs approved by the Authority other than the CCA Program shall be shared among the Parties on such basis as the Board shall determine pursuant to an Authority Document.

ARTICLE 7
WITHDRAWAL AND TERMINATION

7.1 **Withdrawal**.

7.1.1 **General.**

7.1.1.1 Prior to the Authority's execution of Program Agreement 1, any Party may withdraw its membership in the Authority by giving no less than 30 days advance written notice of its election to do so, which notice shall be given to the Authority and each Party. To permit consideration by the governing body of each Party, the Authority shall provide a copy of the proposed Program Agreement 1 to each Party at least 90 days prior to the consideration of such agreement by the Board.

7.1.1.2 Subsequent to the Authority's execution of Program Agreement 1, a Party may withdraw its membership in the Authority, effective as of the beginning of the Authority's fiscal year, by giving no less than 6 months advance written notice of its election to do so, which notice shall be given to the Authority and each Party, and upon such other conditions as may be prescribed in Program Agreement 1.

7.1.2 Amendment. Notwithstanding Section 7.1.1, a Party may withdraw its membership in the Authority following an amendment to this Agreement in the manner provided by Section 8.4.

7.1.3 Continuing Liability; Further Assurances. A Party that withdraws its membership in the Authority may be subject to certain continuing liabilities, as described in Section 7.3. The withdrawing Party and the Authority shall execute and deliver all further instruments and documents, and take any further action that may be reasonably necessary, as determined by the Board, to effectuate the orderly withdrawal of such Party from membership in the Authority. The Operating Rules and Regulations shall prescribe the rights if any of a withdrawn Party to continue to participate in those Board discussions and decisions affecting customers of the CCA Program that reside or do business within the jurisdiction of the Party.

7.2 <u>Involuntary Termination of a Party</u>. This Agreement may be terminated with respect to a Party for material non-compliance with provisions of this Agreement or the Authority Documents upon an affirmative vote of the Board in which the minimum percentage vote and percentage voting shares, as described in Section 4.9.1, shall be no less than 67%, excluding the vote and voting shares of the Party subject to possible termination. Prior to any vote to terminate this Agreement with respect to a Party, written notice of the proposed termination and the reason(s) for such termination shall be delivered to the Party whose termination is proposed at least 30 days prior to the regular Board meeting at which such matter shall first be discussed as an agenda item. The written notice of proposed termination shall specify the particular provisions of this Agreement or the Authority Documents that the Party has allegedly violated. The Party subject to possible termination shall have the opportunity at the next regular Board meeting to respond to any reasons and allegations that may be cited as a basis for termination prior to a vote regarding termination. A Party that has had its membership in the Authority terminated may be subject to certain continuing liabilities, as described in Section 7.3. In the event that the Authority decides to not implement the CCA Program, the minimum percentage vote of 67% shall be conducted in accordance with Section 4.10 rather than Section 4.9.1.

7.3 <u>Continuing Liability; Refund</u>. Upon a withdrawal or involuntary termination of a Party, the Party shall remain responsible for any claims, demands, damages, or liabilities arising from the Party's membership in the Authority through the date of its withdrawal or involuntary termination, it being agreed that the Party shall not be responsible for any claims, demands, damages, or liabilities arising after the date of the Party's withdrawal or involuntary termination. In addition, such

Party also shall be responsible for any costs or obligations associated with the Party's participation in any program in accordance with the provisions of any agreements relating to such program provided such costs or obligations were incurred prior to the withdrawal of the Party. The Authority may withhold funds otherwise owing to the Party or may require the Party to deposit sufficient funds with the Authority, as reasonably determined by the Authority, to cover the Party's liability for the costs described above. Any amount of the Party's funds held on deposit with the Authority above that which is required to pay any liabilities or obligations shall be returned to the Party.

7.4 **Mutual Termination**. This Agreement may be terminated by mutual agreement of all the Parties; provided, however, the foregoing shall not be construed as limiting the rights of a Party to withdraw its membership in the Authority, and thus terminate this Agreement with respect to such withdrawing Party, as described in Section 7.1.

7.5 **Disposition of Property upon Termination of Authority**. Upon termination of this Agreement as to all Parties, any surplus money or assets in possession of the Authority for use under this Agreement, after payment of all liabilities, costs, expenses, and charges incurred under this Agreement and under any program documents, shall be returned to the then-existing Parties in proportion to the contributions made by each.

ARTICLE 8
MISCELLANEOUS PROVISIONS

8.1 **Dispute Resolution**. The Parties and the Authority shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. Should such efforts to settle a dispute, after reasonable efforts, fail, the dispute shall be settled by binding arbitration in accordance with policies and procedures established by the Board.

8.2 **Liability of Directors, Officers, and Employees**. The Directors, officers, and employees of the Authority shall use ordinary care and reasonable diligence in the exercise of their powers and in the performance of their duties pursuant to this Agreement. No current or former Director, officer, or employee will be responsible for any act or omission by another Director, officer, or employee. The Authority shall defend, indemnify and hold harmless the individual current and former Directors, officers, and employees for any acts or omissions in the scope of their employment or duties in the manner provided by Government Code Section 995 et seq. Nothing in this section shall be construed to limit the defenses available under the law, to the Parties, the Authority, or its Directors, officers, or employees.

8.3 **<u>Indemnification of Parties</u>.** The Authority shall acquire such insurance coverage as is necessary to protect the interests of the Authority, the Parties and the public. The Authority shall defend, indemnify and hold harmless the Parties and each of their respective Board or Council members, officers, agents and employees, from any and all claims, losses, damages, costs, injuries and liabilities of every kind arising directly or indirectly from the conduct, activities, operations, acts, and omissions of the Authority under this Agreement.

8.4 **<u>Amendment of this Agreement</u>**. This Agreement may be amended by an affirmative vote of the Board in which the minimum percentage vote and percentage voting shares, as described in Section 4.9.1, shall be no less than 67%. The Authority shall provide written notice to all Parties of amendments to this Agreement, including the effective date of such amendments. A Party shall be deemed to have withdrawn its membership in the Authority effective immediately upon the vote of the Board approving an amendment to this Agreement if the Director representing such Party has provided notice to the other Directors immediately preceding the Board's vote of the Party's intention to withdraw its membership in the Authority should the amendment be approved by the Board. As described in Section 7.3, a Party that withdraws its membership in the Authority in accordance with the above-described procedure may be subject to continuing liabilities incurred prior to the Party's withdrawal. In the event that the Authority decides to not implement the CCA Program, the minimum percentage vote of 67% shall be conducted in accordance with Section 4.10 rather than Section 4.9.1.

8.5 **<u>Assignment</u>**. Except as otherwise expressly provided in this Agreement, the rights and duties of the Parties may not be assigned or delegated without the advance written consent of all of the other Parties, and any attempt to assign or delegate such rights or duties in contravention of this Section 8.5 shall be null and void. This Agreement shall inure to the benefit of, and be binding upon, the successors and assigns of the Parties. This Section 8.5 does not prohibit a Party from entering into an independent agreement with another agency, person, or entity regarding the financing of that Party's contributions to the Authority, or the disposition of proceeds which that Party receives under this Agreement, so long as such independent agreement does not affect, or purport to affect, the rights and duties of the Authority or the Parties under this Agreement.

8.6 **<u>Severability</u>**. If one or more clauses, sentences, paragraphs or provisions of this Agreement shall be held to be unlawful, invalid or unenforceable, it is hereby agreed by the Parties, that the remainder of the Agreement shall not be affected thereby. Such clauses, sentences, paragraphs or provision shall be deemed reformed so as to be lawful, valid and enforced to the maximum extent possible.

8.7 **<u>Further Assurances</u>**. Each Party agrees to execute and deliver all further instruments and documents, and take any further action that may be reasonably necessary, to effectuate the purposes and intent of this Agreement.

8.8 **<u>Execution by Counterparts</u>**. This Agreement may be executed in any number of counterparts, and upon execution by all Parties, each executed counterpart shall have the same force and effect as an original instrument and as if all Parties had signed the same instrument. Any signature page of this Agreement may be detached from any counterpart of this Agreement without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of this Agreement identical in form hereto but having attached to it one or more signature pages.

8.9 **<u>Parties to be Served Notice</u>**. Any notice authorized or required to be given pursuant to this Agreement shall be validly given if served in writing either personally, by deposit in the United States mail, first class postage prepaid with return receipt requested, or by a recognized courier service. Notices given (a) personally or by courier service shall be conclusively deemed received at the time of delivery and receipt and (b) by mail shall be conclusively deemed given 48 hours after the deposit thereof (excluding Saturdays, Sundays and holidays) if the sender receives the return receipt. All notices shall be addressed to the office of the clerk or secretary of the Authority or Party, as the case may be, or such other person designated in writing by the Authority or Party. Notices given to one Party shall be copied to all other Parties. Notices given to the Authority shall be copied to all Parties.

Exhibit A

To the
Joint Powers Agreement
Marin Energy Authority

-Definitions-

"AB 117" means Assembly Bill 117 (Stat. 2002, ch. 838, codified at Public Utilities Code Section 366.2), which created CCA.

"Act" means the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 *et seq*.)

"Administrative Services Agreement" means an agreement or agreements entered into after the Effective Date by the Authority with an entity that will perform tasks necessary for planning, implementing, operating and administering the CCA Program or any other energy programs adopted by the Authority.

"Agreement" means this Joint Powers Agreement.

"Annual Energy Use" has the meaning given in Section 4.9.2.2.

"Authority" means the Marin Energy Authority.

"Authority Document(s)" means document(s) duly adopted by the Board by resolution or motion implementing the powers, functions and activities of the Authority, including but not limited to the Operating Rules and Regulations, the annual budget, and plans and policies.

"Board" means the Board of Directors of the Authority.

"CCA" or "Community Choice Aggregation" means an electric service option available to cities and counties pursuant to Public Utilities Code Section 366.2.

"CCA Program" means the Authority's program relating to CCA that is principally described in Sections 2.4 and 5.1.

"Director" means a member of the Board of Directors representing a Party.

"Effective Date" means the date on which this Agreement shall become effective and the Marin Energy Authority shall exist as a separate public agency, as further described in Section 2.1.

"Implementation Plan" means the plan generally described in Section 5.1.2 of this Agreement that is required under Public Utilities Code Section 366.2 to be filed with the

California Public Utilities Commission for the purpose of describing a proposed CCA Program.

"Initial Costs" means all costs incurred by the Authority relating to the establishment and initial operation of the Authority, such as the hiring of an Executive Director and any administrative staff, any required accounting, administrative, technical and legal services in support of the Authority's initial activities or in support of the negotiation, preparation and approval of one or more Administrative Services Provider Agreements and Program Agreement 1. Administrative and operational costs incurred after the approval of Program Agreement 1 shall not be considered Initial Costs.

"Initial Participants" means, for the purpose of this Agreement, the signatories to this JPA as of May 5, 2010 including City of Belvedere, Town of Fairfax, City of Mill Valley, Town of San Anselmo, City of San Rafael, City of Sausalito, Town of Tiburon and County of Marin.

"Operating Rules and Regulations" means the rules, regulations, policies, bylaws and procedures governing the operation of the Authority.

"Parties" means, collectively, the signatories to this Agreement that have satisfied the conditions in Sections 2.2 or 3.2 such that it is considered a member of the Authority.

"Party" means, singularly, a signatory to this Agreement that has satisfied the conditions in Sections 2.2 or 3.2 such that it is considered a member of the Authority.

"Program Agreement 1" means the agreement that the Authority will enter into with an energy service provider that will provide the electricity to be distributed to customers participating in the CCA Program.

"Total Annual Energy" has the meaning given in Section 4.9.2.2.

Exhibit B

To the
Joint Powers Agreement
Marin Energy Authority

-List of the Parties-

City of American Canyon
City of Belvedere
City of Benicia
City of Calistoga
Town of Corte Madera
City of El Cerrito
Town of Fairfax
City of Larkspur
City of Lafayette
City of Mill Valley
City of Napa
City of Novato
City of Richmond
Town of Ross
Town of San Anselmo
City of San Pablo
City of San Rafael
City of Sausalito
City of St. Helena
Town of Tiburon
City of Walnut Creek
Town of Yountville
County of Marin
County of Napa

Appendix I. MCE’s approval for inclusion of Contra Costa

MCE Clean Energy
My community. My choice.

1125 Tamalpais Avenue
San Rafael, CA 94901

1 (888) 632-3674
mceCleanEnergy.org

November 8, 2016

John Kopchik, Director of Conservation and Development
Contra Costa County
30 Muir Road
Martinez, CA 94553

Dear Mr. Kopchik:

As you may be aware, MCE is currently serving customers in many jurisdictions of Contra Costa County with clean electricity choices at competitive rates for customers. We have been in touch with staff representatives from the County and we are familiar with the technical study currently underway to consider community choice options in other parts of the county not currently served. As part of this process MCE has been asked to clarify what the cost and process would be for new jurisdictions interested in joining MCE.

To respond to this request the MCE Board recently held a Special Meeting to discuss the inclusion process and costs for new jurisdictions within the borders of Contra Costa County. We are pleased to inform you that our Board has approved a six-month "inclusion period" that would allow no-cost membership consideration if your membership application is completed between December 1, 2016 and May 31, 2017.

Membership application requirements are attached here and include the following:

- Adoption of a resolution requesting membership
- Adoption of the ordinance required by the Public Utilities Code Section 366.2(c) (10)
- Executed Memorandum of Understanding
- Signed request for load data from PG&E
- County assessor data for all building stock in jurisdiction
- Designation of a staff person from your county to serve as a liaison to MCE

If you are interested in submitting a membership application please notify Alex DiGiorgio, MCE's Community Development Manager, and he will assist you with any questions you may have as you complete the checklist. You can reach Alex by email at: adiorgio@mcecleanenergy.org or by phone at: 415-464-6031.

Please note that (1) adoption of your Ordinance to join MCE will be subject to approval by the MCE Board, and (2) MCE will conduct an economic feasibility analysis prior to approving membership. Also, if membership is approved, timing of procurement and customer enrollment would be determined by the MCE Board. We will remain in close contact with your county about the most likely target dates for each process.

To streamline communications and policy setting, participating jurisdictions may consolidate voting representation on the MCE Board. If you choose this option, the selected representative would have a weighted vote based on the combined customer load of all the jurisdictions which voted to consolidate.

We are happy to meet with you or your council to answer questions or provide additional information. We look forward to the opportunity to work with you on your membership application for MCE service. Please let me know if we can be of any further assistance.

Sincerely,

Dawn Weisz
CEO

Appendix J. EBCE's Joint Powers Agreement

East Bay Community Energy Authority

- Joint Powers Agreement –

Effective ______________

Among The Following Parties:

EAST BAY COMMUNITY ENERGY AUTHORITY

JOINT POWERS AGREEMENT

This Joint Powers Agreement ("Agreement"), effective as of _________, is made and entered into pursuant to the provisions of Title 1, Division 7, Chapter 5, Article 1 (Section 6500 *et seq*.) of the California Government Code relating to the joint exercise of powers among the parties set forth in Exhibit A ("Parties"). The term "Parties" shall also include an incorporated municipality or county added to this Agreement in accordance with Section 3.1.

RECITALS

1. The Parties are either incorporated municipalities or counties sharing various powers under California law, including but not limited to the power to purchase, supply, and aggregate electricity for themselves and their inhabitants.

2. In 2006, the State Legislature adopted AB 32, the Global Warming Solutions Act, which mandates a reduction in greenhouse gas emissions in 2020 to 1990 levels. The California Air Resources Board is promulgating regulations to implement AB 32 which will require local government to develop programs to reduce greenhouse gas emissions.

3. The purposes for the Initial Participants (as such term is defined in Section 1.1.16 below) entering into this Agreement include securing electrical energy supply for customers in participating jurisdictions, addressing climate change by reducing energy related greenhouse gas emissions, promoting electrical rate price stability, and fostering local economic benefits such as jobs creation, community energy programs and local power development. It is the intent of this Agreement to promote the development and use of a wide range of renewable energy sources and energy efficiency programs, including but not limited to State, regional and local solar and wind energy production.

4. The Parties desire to establish a separate public agency, known as the East Bay Community Energy Authority ("Authority"), under the provisions of the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 *et seq*.) ("Act") in order to collectively study, promote, develop, conduct, operate, and manage energy programs.

5. The Initial Participants have each adopted an ordinance electing to implement through the Authority a Community Choice Aggregation program pursuant to California Public Utilities Code Section 366.2 ("CCA Program"). The first priority of the Authority will be the consideration of those actions necessary to implement the CCA Program.

6. By establishing the Authority, the Parties seek to:

   (a) Provide electricity rates that are lower or competitive with those offered by PG&E for similar products;

(b) Offer differentiated energy options (e.g. 33% or 50% qualified renewable) for default service, and a 100% renewable content option in which customers may "opt-up" and voluntarily participate;

(c) Develop an electric supply portfolio with a lower greenhouse gas (GHG) intensity than PG&E, and one that supports the achievement of the parties' greenhouse gas reduction goals and the comparable goals of all participating jurisdictions;

(d) Establish an energy portfolio that prioritizes the use and development of local renewable resources and minimizes the use of unbundled renewable energy credits;

(e) Promote an energy portfolio that incorporates energy efficiency and demand response programs and has aggressive reduced consumption goals;

(f) Demonstrate quantifiable economic benefits to the region (e.g. union and prevailing wage jobs, local workforce development, new energy programs, and increased local energy investments);

(g) Recognize the value of workers in existing jobs that support the energy infrastructure of Alameda County and Northern California. The Authority, as a leader in the shift to a clean energy, commits to ensuring it will take steps to minimize any adverse impacts to these workers to ensure a "just transition" to the new clean energy economy;

(h) Deliver clean energy programs and projects using a stable, skilled workforce through such mechanisms as project labor agreements, or other workforce programs that are cost effective, designed to avoid work stoppages, and ensure quality;

(i) Promote personal and community ownership of renewable resources, spurring equitable economic development and increased resilience, especially in low income communities;

(j) Provide and manage lower cost energy supplies in a manner that provides cost savings to low-income households and promotes public health in areas impacted by energy production; and

(k) Create an administering agency that is financially sustainable, responsive to regional priorities, well managed, and a leader in fair and equitable treatment of employees through adopting appropriate best practices employment policies, including, but not limited to, promoting efficient consideration of petitions to unionize, and providing appropriate wages and benefits.

AGREEMENT

NOW, THEREFORE, in consideration of the mutual promises, covenants, and conditions hereinafter set forth, it is agreed by and among the Parties as follows:

ARTICLE 1
CONTRACT DOCUMENTS

1.1 **Definitions.** Capitalized terms used in the Agreement shall have the meanings specified below, unless the context requires otherwise.

1.1.1 "AB 117" means Assembly Bill 117 (Stat. 2002, ch. 838, codified at Public Utilities Code Section 366.2), which created CCA.

1.1.2 "Act" means the Joint Exercise of Powers Act of the State of California (Government Code Section 6500 *et seq*.)

1.1.3 "Agreement" means this Joint Powers Agreement.

1.1.4 "Annual Energy Use" has the meaning given in Section 1.1.23.

1.1.5 "Authority" means the East Bay Community Energy Authority established pursuant to this Joint Powers Agreement.

1.1.6 "Authority Document(s)" means document(s) duly adopted by the Board by resolution or motion implementing the powers, functions and activities of the Authority, including but not limited to the Operating Rules and Regulations, the annual budget, and plans and policies.

1.1.7 "Board" means the Board of Directors of the Authority.

1.1.8 "Community Choice Aggregation" or "CCA" means an electric service option available to cities and counties pursuant to Public Utilities Code Section 366.2.

1.1.9 "CCA Program" means the Authority's program relating to CCA that is principally described in Sections 2.4 and 5.1.

1.1.10 "Days" shall mean calendar days unless otherwise specified by this Agreement.

1.1.11 "Director" means a member of the Board of Directors representing a Party, including an alternate Director.

1.1.12 "Effective Date" means the date on which this Agreement shall become effective and the East Bay Community Energy Authority shall exist as a separate public agency, as further described in Section 2.1.

1.1.13 "Ex Officio Board Member" means a non-voting member of the Board of Directors as described in Section 4.2.2. The Ex Officio Board Member may not serve on the Executive Committee of the Board or participate in closed session meetings of the Board.

1.1.14 "Implementation Plan" means the plan generally described in Section 5.1.2 of this Agreement that is required under Public Utilities Code Section 366.2 to be filed with the California Public Utilities Commission for the purpose of describing a proposed CCA Program.

1.1.15 "Initial Costs" means all costs incurred by the Authority relating to the establishment and initial operation of the Authority, such as the hiring of a Chief Executive Officer and any administrative staff, any required accounting, administrative, technical and legal services in support of the Authority's initial formation activities or in support of the negotiation, preparation and approval of power purchase agreements. The Board shall determine the termination date for Initial Costs.

1.1.16 "Initial Participants" means, for the purpose of this Agreement the County of Alameda, the Cities of Albany, Berkeley, Emeryville, Oakland, Piedmont, San Leandro, Hayward, Union City, Newark, Fremont, Dublin, Pleasanton and Livermore.

1.1.17 "Operating Rules and Regulations" means the rules, regulations, policies, bylaws and procedures governing the operation of the Authority.

1.1.18 "Parties" means, collectively, the signatories to this Agreement that have satisfied the conditions in Sections 2.2 or 3.1 such that it is considered a member of the Authority.

1.1.19 "Party" means, singularly, a signatory to this Agreement that has satisfied the conditions in Sections 2.2 or 3.1 such that it is considered a member of the Authority.

1.1.20 "Percentage Vote" means a vote taken by the Board pursuant to Section 4.12.1 that is based on each Party having one equal vote.

1.1.21 "Total Annual Energy" has the meaning given in Section 1.1.23.

1.1.22 "Voting Shares Vote" means a vote taken by the Board pursuant to Section 4.12.2 that is based on the voting shares of each Party described in Section 1.1.23 and set forth in Exhibit C to this Agreement. A Voting Shares vote cannot take place on a matter unless the matter first receives an affirmative or tie Percentage Vote in the manner required by Section 4.12.1 and three or more Directors immediately thereafter request such vote.

1.1.23 "Voting Shares Formula" means the weight applied to a Voting Shares Vote and is determined by the following formula:

(Annual Energy Use/Total Annual Energy) multiplied by 100, where (a) "Annual Energy Use" means (i) with respect to the first two years following the Effective Date, the annual electricity usage, expressed in kilowatt hours ("kWh"), within the Party's respective jurisdiction and (ii) with respect to the period after the second anniversary of the Effective Date, the annual electricity usage, expressed in kWh, of accounts within a Party's respective jurisdiction that are served by the Authority and (b) "Total Annual Energy" means the sum of all Parties' Annual Energy Use. The initial values for Annual Energy use are designated in Exhibit B and the initial voting shares are designated in Exhibit C. Both Exhibits B and C shall be adjusted annually as soon as reasonably practicable after January 1, but no later than March 1 of each year subject to the approval of the Board.

1.2 **Documents Included**. This Agreement consists of this document and the following exhibits, all of which are hereby incorporated into this Agreement.

Exhibit A: List of the Parties

Exhibit B: Annual Energy Use

Exhibit C: Voting Shares

1.3 **Revision of Exhibits**. The Parties agree that Exhibits A, B and C to this Agreement describe certain administrative matters that may be revised upon the approval of the Board, without such revision constituting an amendment to this Agreement, as described in Section 8.4. The Authority shall provide written notice to the Parties of the revision of any such exhibit.

ARTICLE 2
FORMATION OF EAST BAY COMMUNITY ENERGY AUTHORITY

2.1 **Effective Date and Term**. This Agreement shall become effective and East Bay Community Energy Authority shall exist as a separate public agency on December 1, 2016, provided that this Agreement is executed on or prior to such date by at least three Initial Participants after the adoption of the ordinances required by Public Utilities Code Section 366.2(c)(12). The Authority shall provide notice to the Parties of the Effective Date. The Authority shall continue to exist, and this Agreement shall be effective, until this Agreement is terminated in accordance with Section 7.3, subject to the rights of the Parties to withdraw from the Authority.

2.2 **Initial Participants**. Until December 31, 2016, all other Initial Participants may become a Party by executing this Agreement and delivering an executed copy of this Agreement and a copy of the adopted ordinance required by Public Utilities Code Section 366.2(c)(12) to the Authority. Additional conditions, described in Section 3.1, may apply (i) to either an incorporated municipality or county desiring to become a Party that is not an Initial Participant and (ii) to Initial Participants that have not executed and delivered this Agreement within the time period described above.

2.3 **Formation**. There is formed as of the Effective Date a public agency named the East Bay Community Energy Authority. Pursuant to Sections 6506 and 6507 of the Act, the Authority is a public agency separate from the Parties. The debts, liabilities or obligations of the Authority shall not be debts, liabilities or obligations of the individual Parties unless the governing board of a Party agrees in writing to assume any of the debts, liabilities or obligations of the Authority. A Party who has not agreed to assume an Authority debt, liability or obligation shall not be responsible in any way for such debt, liability or obligation even if a majority of the Parties agree to assume the debt, liability or obligation of the Authority. Notwithstanding Section 8.4 of this Agreement, this Section 2.3 may not be amended unless such amendment is approved by the governing boards of all Parties.

2.4 **Purpose**. The purpose of this Agreement is to establish an independent public agency in order to exercise powers common to each Party and any other powers granted to the Authority under state law to participate as a group in the CCA Program pursuant to Public Utilities Code Section 366.2(c)(12); to study, promote, develop, conduct, operate, and manage energy and energy-related climate change programs; and, to exercise all other powers necessary and incidental to accomplishing this purpose.

2.5 **Powers**. The Authority shall have all powers common to the Parties and such additional powers accorded to it by law. The Authority is authorized, in its own name, to exercise all powers and do all acts necessary and proper to carry out the provisions of this Agreement and fulfill its purposes, including, but not limited to, each of the following:

2.5.1 to make and enter into contracts, including those relating to the purchase or sale of electrical energy or attributes thereof;

2.5.2 to employ agents and employees, including but not limited to a Chief Executive Officer and General Counsel;

2.5.3 to acquire, contract, manage, maintain, and operate any buildings, works or improvements, including electric generating facilities;

2.5.4 to acquire property by eminent domain, or otherwise, except as limited under Section 6508 of the Act, and to hold or dispose of any property;

2.5.5 to lease any property;

2.5.6 to sue and be sued in its own name;

2.5.7 to incur debts, liabilities, and obligations, including but not limited to loans from private lending sources pursuant to its temporary borrowing powers such as Government Code Section 53850 *et seq*. and authority under the Act;

2.5.8 to form subsidiary or independent corporations or entities, if appropriate, to carry out energy supply and energy conservation programs at the lowest possible cost consistent with the Authority's CCA Program implementation plan, risk management policies, or to take advantage of legislative or regulatory changes;

2.5.9 to issue revenue bonds and other forms of indebtedness;

2.5.10 to apply for, accept, and receive all licenses, permits, grants, loans or other assistance from any federal, state or local public agency;

2.5.11 to submit documentation and notices, register, and comply with orders, tariffs and agreements for the establishment and implementation of the CCA Program and other energy programs;

2.5.12 to adopt rules, regulations, policies, bylaws and procedures governing the operation of the Authority ("Operating Rules and Regulations");

2.5.13 to make and enter into service, energy and any other agreements necessary to plan, implement, operate and administer the CCA Program and other energy programs, including the acquisition of electric power supply and the provision of retail and regulatory support services; and

2.5.14 to negotiate project labor agreements, community benefits agreements and collective bargaining agreements with the local building trades council and other interested parties.

2.6 **Limitation on Powers**. As required by Government Code Section 6509, the power of the Authority is subject to the restrictions upon the manner of exercising power possessed by the City of Emeryville and any other restrictions on exercising the powers of the Authority that may be adopted by the Board.

2.7 **Compliance with Local Zoning and Building Laws**. Notwithstanding any other provisions of this Agreement or state law, any facilities, buildings or structures located, constructed or caused to be constructed by the Authority within the territory of the Authority shall comply with the General Plan, zoning and building laws of the local jurisdiction within which the facilities, buildings or structures are constructed and comply with the California Environmental Quality Act ("CEQA").

2.8 **Compliance with the Brown Act**. The Authority and its officers and employees shall comply with the provisions of the Ralph M. Brown Act, Government Code Section 54950 *et seq*.

2.9 **Compliance with the Political Reform Act and Government Code Section 1090.** The Authority and its officers and employees shall comply with the Political Reform Act (Government Code Section 81000 *et seq.*) and Government Code Section 1090 *et seq*, and shall adopt a Conflict of Interest Code pursuant to Government Code Section 87300. The Board of Directors may adopt additional conflict of interest regulations in the Operating Rules and Regulations.

ARTICLE 3
AUTHORITY PARTICIPATION

3.1 **Addition of Parties**. Subject to Section 2.2, relating to certain rights of Initial Participants, other incorporated municipalities and counties may become Parties upon (a) the adoption of a resolution by the governing body of such incorporated municipality or county requesting that the incorporated municipality or county, as the case may be, become a member of the Authority, (b) the adoption by an affirmative vote of a majority of all Directors of the entire Board satisfying the requirements described in Section 4.12, of a resolution authorizing membership of the additional incorporated municipality or county, specifying the membership payment, if any, to be made by the additional incorporated municipality or county to reflect its pro rata share of organizational, planning and other pre-existing expenditures, and describing additional conditions, if any, associated with membership, (c) the adoption of an ordinance required by Public Utilities Code Section 366.2(c)(12) and execution of this Agreement and other necessary program agreements by the incorporated municipality or county, (d) payment of the membership fee, if any, and (e) satisfaction of any conditions established by the Board.

3.2 **Continuing Participation**. The Parties acknowledge that membership in the Authority may change by the addition and/or withdrawal or termination of Parties. The Parties agree to participate with such other Parties as may later be added, as described in Section 3.1. The Parties also agree that the withdrawal or termination of a Party shall not affect this Agreement or the remaining Parties' continuing obligations under this Agreement.

ARTICLE 4
GOVERNANCE AND INTERNAL ORGANIZATION

4.1 **Board of Directors**. The governing body of the Authority shall be a Board of Directors ("Board") consisting of one director for each Party appointed in accordance with Section 4.2.

4.2 **Appointment of Directors**. The Directors shall be appointed as follows:

4.2.1 The governing body of each Party shall appoint and designate in writing one regular Director who shall be authorized to act for and on behalf of the Party on matters within the powers of the Authority. The governing body of each Party also shall appoint and designate in writing one alternate Director who may vote on matters when the regular Director is absent from a Board meeting. The person appointed and designated as the regular Director shall be a member of the governing body of the Party. The person appointed and designated as the alternate Director shall also be a member of the governing body of the Party.

4.2.2 The Board shall also include one non-voting ex officio member as defined in Section 1.1.13 ("Ex Officio Board Member"). The Chair of the Community Advisory Committee, as described in Section 4.9 below, shall serve as the Ex Officio Board Member. The Vice Chair of the Community Advisory Committee shall serve as an alternate Ex Officio Board Member when the regular Ex Officio Board Member is absent from a Board meeting.

4.2.3 The Operating Rules and Regulations, to be developed and approved by the Board in accordance with Section 2.5.12 may include rules regarding Directors, such as meeting attendance requirements. No Party shall be deprived of its right to seat a Director on the Board.

4.3 **Terms of Office**. Each regular and alternate Director shall serve at the pleasure of the governing body of the Party that the Director represents, and may be removed as Director by such governing body at any time. If at any time a vacancy occurs on the Board, a replacement shall be appointed to fill the position of the previous Director in accordance with the provisions of Section 4.2 within 90 days of the date that such position becomes vacant.

4.4 **Quorum**. A majority of the Directors of the entire Board shall constitute a quorum, except that less than a quorum may adjourn a meeting from time to time in accordance with law.

4.5 **Powers and Function of the Board**. The Board shall conduct or authorize to be conducted all business and activities of the Authority, consistent with this Agreement, the Authority Documents, the Operating Rules and Regulations, and applicable law. Board approval shall be required for any of the following actions, which are defined as "Essential Functions":

4.5.1 The issuance of bonds or any other financing even if program revenues are expected to pay for such financing.

4.5.2 The hiring of a Chief Executive Officer and General Counsel.

4.5.3 The appointment or removal of an officer.

4.5.4 The adoption of the Annual Budget.

4.5.5 The adoption of an ordinance.

4.5.6 The initiation of resolution of claims and litigation where the Authority will be the defendant, plaintiff, petitioner, respondent, cross complainant or cross petitioner, or intervenor; provided, however, that the Chief Executive Officer or General Counsel, on behalf of the Authority, may intervene in, become party to, or file comments with respect to any proceeding pending at the California Public Utilities Commission, the Federal Energy Regulatory Commission, or any other administrative agency, without approval of the Board. The Board shall adopt Operating Rules and Regulations governing the Chief Executive Officer and General Counsel's exercise of authority under this Section 4.5.6.

4.5.7 The setting of rates for power sold by the Authority and the setting of charges for any other category of service provided by the Authority.

4.5.8 Termination of the CCA Program.

4.6 **Executive Committee**. The Board shall establish an Executive Committee consisting of a smaller number of Directors. The Board may delegate to the Executive Committee such authority as the Board might otherwise exercise, subject to limitations placed on the Board's authority to delegate certain Essential Functions, as described in Section 4.5 and the Operating Rules and Regulations. The Board may not delegate to the Executive Committee or any other committee its authority under Section 2.5.12 to adopt and amend the Operating Rules and Regulations or its Essential Functions listed in Section 4.5. After the Executive Committee meets or otherwise takes action, it shall, as soon as practicable, make a report of its activities at a meeting of the Board.

4.7 **Director Compensation**. Directors shall receive a stipend of $100 per meeting, as adjusted to account for inflation, as provided for in the Authority's Operating Rules and Regulations.

4.8 **Commissions, Boards and Committees**. The Board may establish any advisory commissions, boards and committees as the Board deems appropriate to assist the Board in carrying out its functions and implementing the CCA Program, other energy programs and the provisions of this Agreement. The Board may establish rules, regulations, policies, bylaws or procedures to govern any such commissions, boards, or committees and shall determine whether members shall be compensated or entitled to reimbursement for expenses.

4.9 **Community Advisory Committee**. The Board shall establish a Community Advisory Committee consisting of nine members, none of whom may be voting members of the Board. The function of the Community Advisory Committee shall be to advise the Board of Directors on all subjects related to the operation of the CCA Program as set forth in a work plan adopted by the Board of Directors from time to time, with the exception of personnel and litigation decisions. The Community Advisory Committee is advisory only, and shall not have decision-making authority, or receive any delegation of authority from the Board of Directors. The Board shall publicize the opportunity to serve on the Community Advisory Committee, and shall appoint members of the Community Advisory Committee from those individuals expressing interest in serving, and who represent a diverse cross-section of interests, skill sets and geographic regions. Members of the Community Advisory Committee shall serve staggered four-year terms (the first term of three of the members shall be two years, and four years thereafter), which may be renewed. A member of the Community Advisory Committee may be removed by the Board of Directors by majority vote. The Board of Directors shall determine whether the Community Advisory Committee members will receive a stipend and/or be entitled to reimbursement for expenses.

4.10 <u>Chief Executive Officer</u>. The Board of Directors shall appoint a Chief Executive Officer for the Authority, who shall be responsible for the day-to-day operation and management of the Authority and the CCA Program. The Chief Executive Officer may exercise all powers of the Authority, including the power to hire, discipline and terminate employees as well as the power to approve any agreement, if the expenditure is authorized in the Authority's approved budget, except the powers specifically set forth in Section 4.5 or those powers which by law must be exercised by the Board of Directors. The Board of Directors shall provide procedures and guidelines for the Chief Executive Officer exercising the powers of the Authority in the Operating Rules and Regulations.

4.11 <u>General Counsel.</u> The Board of Directors shall appoint a General Counsel for the Authority, who shall be responsible for providing legal advice to the Board of Directors and overseeing all legal work for the Authority.

4.12 <u>Board Voting</u>.

4.12.1 Percentage Vote. Except when a supermajority vote is expressly required by this Agreement or the Operating Rules and Regulations, action of the Board on all matters shall require an affirmative vote of a majority of all Directors on the entire Board (a "Percentage Vote" as defined in Section 1.1.20). A supermajority vote is required by this Agreement for the matters addressed by Section 8.4. When a supermajority vote is required by this Agreement or the Operating Rules and Regulations, action of the Board shall require an affirmative Percentage Vote of the specified supermajority of all Directors on the entire Board. No action can be taken by the Board without an affirmative Percentage Vote. Notwithstanding the foregoing, in the event of a tie in the Percentage Vote, an action may be approved by an affirmative "Voting Shares Vote," as defined in Section 1.1.22, if three or more Directors immediately request such vote.

4.12.2 Voting Shares Vote. In addition to and immediately after an affirmative percentage vote, three or more Directors may request that, a vote of the voting shares shall be held (a "Voting Shares Vote" as defined in Section 1.1.22). To approve an action by a Voting Shares Vote, the corresponding voting shares (as defined in Section 1.1.23 and Exhibit C) of all Directors voting in the affirmative shall exceed 50% of the voting share of all Directors on the entire Board, or such other higher voting shares percentage expressly required by this Agreement or the Operating Rules and Regulations. In the event that any one Director has a voting share that equals or exceeds that which is necessary to disapprove the matter being voted on by the Board, at least one other Director shall be required to vote in the negative in order to disapprove such matter. When a voting shares vote is held, action by the Board requires both an affirmative Percentage Vote and an affirmative Voting Shares Vote. Notwithstanding the foregoing, in the event of a tie in the Percentage Vote, an action may be approved on an affirmative Voting Shares Vote. When a supermajority vote is required by this Agreement or the Operating Rules and Regulations, the supermajority vote is subject to the Voting Share Vote provisions of this Section 4.12.2, and the specified supermajority of all Voting Shares is required for approval of the action, if the provision of this Section 4.12.2 are triggered.

4.13 Meetings and Special Meetings of the Board. The Board shall hold at least four regular meetings per year, but the Board may provide for the holding of regular meetings at more frequent intervals. The date, hour and place of each regular meeting shall be fixed by resolution or ordinance of the Board. Regular meetings may be adjourned to another meeting time. Special and Emergency meetings of the Board may be called in accordance with the provisions of California Government Code Section 54956 and 54956.5. Directors may participate in meetings telephonically, with full voting rights, only to the extent permitted by law.

4.14 Officers.

4.14.1 Chair and Vice Chair. At the first meeting held by the Board in each calendar year, the Directors shall elect, from among themselves, a Chair, who shall be the presiding officer of all Board meetings, and a Vice Chair, who shall serve in the absence of the Chair. The Chair and Vice Chair shall hold office for one year and serve no more than two consecutive terms, however, the total number of terms a Director may serve as Chair or Vice Chair is not limited. The office of either the Chair or Vice Chair shall be declared vacant and the Board shall make a new selection if: (a) the person serving dies, resigns, or ceases to be a member of the governing body of the Party that the person represents; (b) the Party that the person represents removes the person as its representative on the Board, or (c) the Party that he or she represents withdraws from the Authority pursuant to the provisions of this Agreement.

4.14.2 Secretary. The Board shall appoint a Secretary, who need not be a member of the Board, who shall be responsible for keeping the minutes of all meetings of the Board and all other official records of the Authority.

4.14.3 Treasurer and Auditor. The Board shall appoint a qualified person to act as the Treasurer and a qualified person to act as the Auditor, neither of whom needs to be a member of the Board. The same person may not simultaneously hold both the office of Treasurer and the office of the Auditor of the Authority. Unless otherwise exempted from such requirement, the Authority shall cause an independent audit to be made annually by a certified public accountant, or public accountant, in compliance with Section 6505 of the Act. The Treasurer shall act as the depositary of the Authority and have custody of all the money of the Authority, from whatever source, and as such, shall have all of the duties and responsibilities specified in Section 6505.5 of the Act. The Board may require the Treasurer and/or Auditor to file with the Authority an official bond in an amount to be fixed by the Board, and if so requested, the Authority shall pay the cost of premiums associated with the bond. The Treasurer shall report directly to the Board and shall comply with the requirements of treasurers of incorporated municipalities. The Board may transfer the responsibilities of Treasurer to any person or entity as the law may provide at the time.

4.15 **Administrative Services Provider**. The Board may appoint one or more administrative services providers to serve as the Authority's agent for planning, implementing, operating and administering the CCA Program, and any other program approved by the Board, in accordance with the provisions of an Administrative Services Agreement. The appointed administrative services provider may be one of the Parties. The Administrative Services Agreement shall set forth the terms and conditions by which the appointed administrative services provider shall perform or cause to be performed all tasks necessary for planning, implementing, operating and administering the CCA Program and other approved programs. The Administrative Services Agreement shall set forth the term of the Agreement and the circumstances under which the Administrative Services Agreement may be terminated by the Authority. This section shall not in any way be construed to limit the discretion of the Authority to hire its own employees to administer the CCA Program or any other program.

4.16 **Operational Audit**. The Authority shall commission an independent agent to conduct and deliver at a public meeting of the Board an evaluation of the performance of the CCA Program relative to goals for renewable energy and carbon reductions. The Authority shall approve a budget for such evaluation and shall hire a firm or individual that has no other direct or indirect business relationship with the Authority. The evaluation shall be conducted at least once every two years.

ARTICLE 5
IMPLEMENTATION ACTION AND AUTHORITY DOCUMENTS

5.1 Implementation of the CCA Program.

5.1.1 **Enabling Ordinance**. Prior to the execution of this Agreement, each Party shall adopt an ordinance in accordance with Public Utilities Code Section 366.2(c)(12) for the purpose of specifying that the Party intends to implement a CCA Program by and through its participation in the Authority.

5.1.2 Implementation Plan. The Authority shall cause to be prepared an Implementation Plan meeting the requirements of Public Utilities Code Section 366.2 and any applicable Public Utilities Commission regulations as soon after the Effective Date as reasonably practicable. The Implementation Plan shall not be filed with the Public Utilities Commission until it is approved by the Board in the manner provided by Section 4.12.

5.1.3 Termination of CCA Program. Nothing contained in this Article or this Agreement shall be construed to limit the discretion of the Authority to terminate the implementation or operation of the CCA Program at any time in accordance with any applicable requirements of state law.

5.2 **Other Authority Documents**. The Parties acknowledge and agree that the operations of the Authority will be implemented through various documents duly adopted by the Board through Board resolution or minute action, including but not necessarily limited to the Operating Rules and Regulations, the annual budget, and specified plans and policies defined as the Authority Documents by this Agreement. The Parties agree to abide by and comply with the terms and conditions of all such Authority Documents that may be adopted by the Board, subject to the Parties' right to withdraw from the Authority as described in Article 7.

5.3 **Integrated Resource Plan.** The Authority shall cause to be prepared an Integrated Resource Plan in accordance with CPUC regulations that will ensure the long-term development and administration of a variety of energy programs that promote local renewable resources, conservation, demand response, and energy efficiency, while maintaining compliance with the State Renewable Portfolio standard and customer rate competitiveness. The Authority shall prioritize the development of energy projects in Alameda and adjacent counties. Principal aspects of its planned operations shall be in a Business Plan as outlined in Section 5.4 of this Agreement.

5.4 **Business Plan.** The Authority shall cause to be prepared a Business Plan, which will include a roadmap for the development, procurement, and integration of local renewable energy resources as outlined in Section 5.3 of this Agreement. The Business Plan shall include a description of how the CCA Program will contribute to fostering local economic benefits, such as job creation and community energy programs. The Business Plan shall identify opportunities for local power development and how the CCA Program can achieve the goals outlined in Recitals 3 and 6 of this Agreement. The Business Plan shall include specific language detailing employment and labor standards that relate to the execution of the CCA Program as referenced in this Agreement. The Business Plan shall identify clear and transparent marketing practices to be followed by the CCA Program, including the identification of the sources of its electricity and explanation of the various types of electricity procured by the Authority. The Business Plan shall cover the first five (5) years of the operation of the CCA Program. The Business Plan shall be completed by the Authority no later than eight (8) months after the seating of the Authority Board of Directors. Progress on the implementation of the Business Plan shall be subject to annual public review.

5.5 **Labor Organization Neutrality.** The Authority shall remain neutral in the event its employees, and the employees of its subcontractors, if any, wish to unionize.

5.6 **Renewable Portfolio Standards.** The Authority shall provide its customers energy primarily from Category 1 eligible renewable resources, as defined under the California RPS and consistent with the goals of the CCA Program. The Authority shall not procure energy from Category 3 eligible renewable resources (unbundled Renewable Energy Credits or RECs) exceeding 50% of the State law requirements, to achieve its renewable portfolio goals. However, for Category 3 RECs associated with generation facilities located within its service jurisdiction, the limitation set forth in the preceding sentence shall not apply.

ARTICLE 6
FINANCIAL PROVISIONS

6.1 **Fiscal Year**. The Authority's fiscal year shall be 12 months commencing July 1 and ending June 30. The fiscal year may be changed by Board resolution.

6.2 **Depository**.

6.2.1 All funds of the Authority shall be held in separate accounts in the name of the Authority and not commingled with funds of any Party or any other person or entity.

6.2.2 All funds of the Authority shall be strictly and separately accounted for, and regular reports shall be rendered of all receipts and disbursements, at least quarterly during the fiscal year. The books and records of the Authority shall be open to inspection by the Parties at all reasonable times.

6.2.3 All expenditures shall be made in accordance with the approved budget and upon the approval of any officer so authorized by the Board in accordance with its Operating Rules and Regulations. The Treasurer shall draw checks or warrants or make payments by other means for claims or disbursements not within an applicable budget only upon the prior approval of the Board.

6.3 **Budget and Recovery Costs**.

6.3.1 **Budget**. The initial budget shall be approved by the Board. The Board may revise the budget from time to time through an Authority Document as may be reasonably necessary to address contingencies and unexpected expenses. All subsequent budgets of the Authority shall be prepared and approved by the Board in accordance with the Operating Rules and Regulations.

6.3.2 **Funding of Initial Costs**. The County shall fund the Initial Costs of establishing and implementing the CCA Program. In the event that the

CCA Program becomes operational, these Initial Costs paid by the County and any specified interest shall be included in the customer charges for electric services to the extent permitted by law, and the County shall be reimbursed from the payment of such charges by customers of the Authority. The Authority may establish a reasonable time period over which such costs are recovered. In the event that the CCA Program does not become operational, the County shall not be entitled to any reimbursement of the Initial Costs.

6.3.4 Additional Contributions and Advances. Pursuant to Government Code Section 6504, the Parties may in their sole discretion make financial contributions, loans or advances to the Authority for the purposes of the Authority set forth in this Agreement. The repayment of such contributions, loans or advances will be on the written terms agreed to by the Party making the contribution, loan or advance and the Authority.

ARTICLE 7
WITHDRAWAL AND TERMINATION

7.1 Withdrawal.

7.1.1 General Right to Withdraw. A Party may withdraw its membership in the Authority, effective as of the beginning of the Authority's fiscal year, by giving no less than 180 days advance written notice of its election to do so, which notice shall be given to the Authority and each Party. Withdrawal of a Party shall require an affirmative vote of the Party's governing board.

7.1.2 Withdrawal Following Amendment. Notwithstanding Section 7.1.1, a Party may withdraw its membership in the Authority following an amendment to this Agreement provided that the requirements of this Section 7.1.2 are strictly followed. A Party shall be deemed to have withdrawn its membership in the Authority effective 180 days after the Board approves an amendment to this Agreement if the Director representing such Party has provided notice to the other Directors immediately preceding the Board's vote of the Party's intention to withdraw its membership in the Authority should the amendment be approved by the Board.

7.1.3 The Right to Withdraw Prior to Program Launch. After receiving bids from power suppliers for the CCA Program, the Authority must provide to the Parties a report from the electrical utility consultant retained by the Authority comparing the Authority's total estimated electrical rates, the estimated greenhouse gas emissions rate and the amount of estimated renewable energy to be used with that of the incumbent utility. Within 30 days after receiving this report, through its City Manager or a person expressly authorized by the Party, any Party may immediately withdraw its membership in the Authority by providing written notice of withdrawal to the Authority if the report determines that any one of the following conditions exists: (1) the Authority is unable to provide total electrical rates, as part of its baseline offering to customers, that are equal to or lower than the incumbent utility, (2) the Authority is unable to provide electricity in a manner that has a lower greenhouse gas emissions rate than the incumbent utility, or (3) the Authority will use less qualified renewable energy than the incumbent utility. Any Party who withdraws from the Authority pursuant to this Section 7.1.3 shall not be entitled to any refund of the Initial Costs it has paid to the Authority prior to the date of withdrawal unless the Authority is later terminated pursuant to Section 7.3. In such event, any Initial Costs not expended by the Authority shall be returned to all Parties, including any Party that has withdrawn pursuant to this section, in proportion to the contribution that each made. Notwithstanding anything to the contrary in this Agreement, any Party who withdraws pursuant to this section shall not be responsible for any liabilities or obligations of the Authority after the date of withdrawal, including without limitation any liability arising from power purchase agreements entered into by the Authority.

7.2 **<u>Continuing Liability After Withdrawal; Further Assurances; Refund</u>.** A Party that withdraws its membership in the Authority under either Section 7.1.1 or 7.1.2 shall be responsible for paying its fair share of costs incurred by the Authority resulting from the Party's withdrawal, including costs from the resale of power contracts by the Authority to serve the Party's load and any similar costs directly attributable to the Party's withdrawal, such costs being limited to those contracts executed while the withdrawing Party was a member, and administrative costs associated thereto. The Parties agree that such costs shall not constitute a debt of the withdrawing Party, accruing interest, or having a maturity date. The Authority may withhold funds otherwise owing to the Party or may require the Party to deposit sufficient funds with the Authority, as reasonably determined by the Authority, to cover the Party's costs described above. Any amount of the Party's funds held by the Authority for the benefit of the Party that are not required to pay the Party's costs described above shall be returned to the Party. The withdrawing party and the Authority shall execute and deliver all further instruments and documents, and take any further action that may be reasonably necessary, as determined by the Board, to effectuate the orderly withdrawal of such Party from membership in the Authority. A withdrawing party has the right to continue to participate in Board discussions and decisions affecting customers of the CCA Program that reside or do business within the jurisdiction of the Party until the withdrawal's effective date.

7.3 **<u>Mutual Termination</u>**. This Agreement may be terminated by mutual agreement of all the Parties; provided, however, the foregoing shall not be construed as limiting the rights of a Party to withdraw its membership in the Authority, and thus terminate this Agreement with respect to such withdrawing Party, as described in Section 7.1.

7.4 **<u>Disposition of Property upon Termination of Authority</u>**. Upon termination of this Agreement as to all Parties, any surplus money or assets in possession of the Authority for use under this Agreement, after payment of all liabilities, costs, expenses, and charges incurred under this Agreement and under any Authority Documents, shall be returned to the then-existing Parties in proportion to the contributions made by each.

ARTICLE 8
MISCELLANEOUS PROVISIONS

8.1 Dispute Resolution. The Parties and the Authority shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. Before exercising any remedy provided by law, a Party or the Parties and the Authority shall engage in nonbinding mediation in the manner agreed upon by the Party or Parties and the Authority. The Parties agree that each Party may specifically enforce this section 8.1. In the event that nonbinding mediation is not initiated or does not result in the settlement of a dispute within 120 days after the demand for mediation is made, any Party and the Authority may pursue any remedies provided by law.

8.2 Liability of Directors, Officers, and Employees. The Directors, officers, and employees of the Authority shall use ordinary care and reasonable diligence in the exercise of their powers and in the performance of their duties pursuant to this Agreement. No current or former Director, officer, or employee will be responsible for any act or omission by another Director, officer, or employee. The Authority shall defend, indemnify and hold harmless the individual current and former Directors, officers, and employees for any acts or omissions in the scope of their employment or duties in the manner provided by Government Code Section 995 *et seq*. Nothing in this section shall be construed to limit the defenses available under the law, to the Parties, the Authority, or its Directors, officers, or employees.

8.3 Indemnification of Parties. The Authority shall acquire such insurance coverage as the Board deems necessary to protect the interests of the Authority, the Parties and the public. Such insurance coverage shall name the Parties and their respective Board or Council members, officers, agents and employees as additional insureds. The Authority shall defend, indemnify and hold harmless the Parties and each of their respective Board or Council members, officers, agents and employees, from any and all claims, losses, damages, costs, injuries and liabilities of every kind arising directly or indirectly from the conduct, activities, operations, acts, and omissions of the Authority under this Agreement.

8.4 Amendment of this Agreement. This Agreement may be amended in writing by a two-thirds affirmative vote of the entire Board satisfying the requirements described in Section 4.12. Except that, any amendment to the voting provisions in Section 4.12 may only be made by a three-quarters affirmative vote of the entire Board. The Authority shall provide written notice to the Parties at least 30 days in advance of any proposed amendment being considered by the Board. If the proposed amendment is adopted by the Board, the Authority shall provide prompt written notice to all Parties of the effective date of such amendment along with a copy of the amendment.

8.5 **Assignment**. Except as otherwise expressly provided in this Agreement, the rights and duties of the Parties may not be assigned or delegated without the advance written consent of all of the other Parties, and any attempt to assign or delegate such rights or duties in contravention of this Section 8.5 shall be null and void. This Agreement shall inure to the benefit of, and be binding upon, the successors and assigns of the Parties. This Section 8.5 does not prohibit a Party from entering into an independent agreement with another agency, person, or entity regarding the financing of that Party's contributions to the Authority, or the disposition of proceeds which that Party receives under this Agreement, so long as such independent agreement does not affect, or purport to affect, the rights and duties of the Authority or the Parties under this Agreement.

8.6 **Severability**. If one or more clauses, sentences, paragraphs or provisions of this Agreement shall be held to be unlawful, invalid or unenforceable, it is hereby agreed by the Parties, that the remainder of the Agreement shall not be affected thereby. Such clauses, sentences, paragraphs or provision shall be deemed reformed so as to be lawful, valid and enforced to the maximum extent possible.

8.7 **Further Assurances**. Each Party agrees to execute and deliver all further instruments and documents, and take any further action that may be reasonably necessary, to effectuate the purposes and intent of this Agreement.

8.8 **Execution by Counterparts**. This Agreement may be executed in any number of counterparts, and upon execution by all Parties, each executed counterpart shall have the same force and effect as an original instrument and as if all Parties had signed the same instrument. Any signature page of this Agreement may be detached from any counterpart of this Agreement without impairing the legal effect of any signatures thereon, and may be attached to another counterpart of this Agreement identical in form hereto but having attached to it one or more signature pages.

8.9 **Parties to be Served Notice**. Any notice authorized or required to be given pursuant to this Agreement shall be validly given if served in writing either personally, by deposit in the United States mail, first class postage prepaid with return receipt requested, or by a recognized courier service. Notices given (a) personally or by courier service shall be conclusively deemed received at the time of delivery and receipt and (b) by mail shall be conclusively deemed given 72 hours after the deposit thereof (excluding Saturdays, Sundays and holidays) if the sender receives the return receipt. All notices shall be addressed to the office of the clerk or secretary of the Authority or Party, as the case may be, or such other person designated in writing by the Authority or Party. In addition, a duplicate copy of all notices provided pursuant to this section shall be provided to the Director and alternate Director for each Party. Notices given to one Party shall be copied to all other Parties. Notices given to the Authority shall be copied to all Parties. All notices required hereunder shall be delivered to:

The County of Alameda

Director, Community Development Agency

224 West Winton Ave.
Hayward, CA 94612

With a copy to:

Office of the County Counsel
1221 Oak Street, Suite 450
Oakland, CA 94612

if to [PARTY No. ____]

Office of the City Clerk
____
____

Office of the City Manager/Administrator
____
____

Office of the City Attorney
____
____

if to [PARTY No._____]

Office of the City Clerk
____
____

Office of the City Manager/Administrator
____
____

Office of the City Attorney
____
____

ARTICLE 9
SIGNATURE

IN WITNESS WHEREOF, the Parties hereto have executed this Joint Powers Agreement establishing the East Bay Community Energy Authority.

By: ________________________________

Name: ______________________________

Title: ______________________________

Date: ______________________________

Party: ______________________________

EXHIBIT A

-LIST OF THE PARTIES

(This draft exhibit is based on the assumption that all of the Initial Participants will become Parties. On the Effective Date, this exhibit will be revised to reflect the Parties to this Agreement at that time.)-

-

DRAFT EXHIBIT B

-ANNUAL ENERGY USE

(This draft exhibit is based on the assumption that <u>all</u> of the Initial Participants will become Parties. On the Effective Date, this exhibit will be revised to reflect the Parties to this Agreement at that time.)

This Exhibit B is effective as of ________________.

Party	**kWh ([YEAR]*)**

*Data provided by PG&E

DRAFT EXHIBIT C

- VOTING SHARES

(This draft exhibit is based on the assumption that all of the Initial Participants will become Parties. On the Effective Date, this exhibit will be revised to reflect the Parties to this Agreement at that time.)

This Exhibit C is effective as of ____________________.

Party	kWh ([YEAR]*)	Voting Share Section 4.11.2
Total		

*Data provided by PG&E

Appendix K. EBCE's offer for inclusion of Contra Costa

February 21, 2017

John Kopchik
Director, Department of Conservation and Development
Contra Costa County
30 Muir Street
Martinez, CA 94553

Dear Mr. Kopchik:

This letter is in response to your request for East Bay Community Energy (EBCE) to indicate its desire to expand beyond Alameda County and its willingness to engage interested Contra Costa County jurisdictions as EBCE members. This letter also outlines the terms of EBCE membership.

As you may know, the EBCE Board of Directors met for the first time on January 30, 2017. During that meeting, the Board had a robust discussion on this topic and was strongly in favor of formally inviting Contra Costa County and its Cities to join EBCE. The general sense was that it would be an exciting and positive development to have a more regionally focused East Bay Community Choice Energy (CCE) program. Some EBCE Board members expressed a willingness to present at your upcoming Board of Supervisors and City Council meetings as Contra Costa County officials deliberate on which CCE option would be in the best interests of their constituents.

With regards to the terms of membership, the EBCE Board discussed each of the points your letter raised, and we can provide you the following feedback:

- ***Cost to Join:*** The Board agreed that there would be no cost for Contra Costa County jurisdictions to join the JPA. EBCE will absorb all of the initial launch expenses, including load data analysis, communications costs and noticing requirements. The Board believes these one-time costs are offset by the longer-term value of including Contra Costa County communities in order to form a larger, regional program. We do request, however, that new member jurisdictions identify appropriate municipal staff to assist in coordinating the JPA resolution and Agreement, passage of the CCE ordinance and help with local public outreach, such as organizing workshops and having a presence at community events.

- ***Required actions and steps in the membership process:*** The Board agreed that the steps for joining EBCE would be the same as for the Alameda County jurisdictions, namely that the prospective members must pass the required CCA ordinance, authorize access to their load data, hold at least two duly noticed public hearings, and pass the JPA resolution in order to become a party to the EBCE Joint Powers Agreement. A copy of the CCE ordinance, JPA Agreement and JPA resolution are attached for your reference. For the purposes of completing EBCE's implementation plan, conducting public outreach, and procuring power for customers in new member jurisdictions, we request that interested jurisdictions cast deciding votes by June 30, 2017. It should be noted that there will be additional opportunities to join EBCE in 2018, if that is preferred. See below for more information regarding timimg.

- ***Representation on EBCE Board:*** Each Contra Costa County jurisdiction choosing to join EBCE will have a seat on its Board, which is the same manner of representation as other Alameda County members. As you may know, EBCE has a two-tiered voting structure, the first being one-city/one-vote with simple majority to carry the vote. In this case, every jurisdiction will have one equal vote, and it is anticipated that most votes will proceed in this fashion. However, if at least three members call for a weighted vote, then each city's voting share would be determined by its electrical load; weighted votes may only be used to overturn an affirmative vote and may not be used to resurrect or overturn a negative vote. Please see Attachment 4 for a comparision of EBCE and CCCo jurisdictional loads. New Board members can be seated once the JPA resolution has been passed, and the first and second readings of the CCE ordinance are complete.

- ***Estimated date of service commencement:*** Your letter asked for a date when electric service could begin. As of this writing, it is likely that EBCE will begin serving Phase 1 customers (a subset of the total number of accounts) in Spring of 2018. Phase 2 customers, including additional Contra Costa County accounts, would be enrolled in the Summer or Fall of 2018. Cities that join after the June 30th deadline or in 2018 will be enrolled in Phase 3, likely to be the late Fall of 2018 or Spring of 2019.

The EBCE Board is excited about the prospect of creating a regional East Bay Community Energy program. A member of our Board and Alameda County interim staff will attempt to attend as many of your upcoming presentations as possible, including the Board of Supervisors meeting on March 21. If possible, we would very much like the opportunity to make a more formal presentation at that meeting if the Contra Costa County Board of Supervisors and staff are agreeable.

Finally, for the purposes of planning, it would be helpful to know how many Contra Costa County jurisdictions would be interested in joining EBCE. As noted above, we are requesting that the County and any interested cities complete their decision-making and passage of the required resolution and ordinance by June 30, 2017 if they are interested in a Spring/Summer 2018 enrollment period.

We hope this addresses your questions on behalf of Contra Costa County and interested cities. Please don't hesitate to contact us if you'd like to discuss any of these matters further.

Sincerely Yours,

Chris Bazar
Director, Alameda County Community Development Agency

Cc: EBCE Board of Directors

Attachments:

1) EBCE JPA Agreement and sample resolution
2) Copy of CCE ordinance
3) PG&E Attestation form for load data authorization
4) Load size / voting shares comparision by jurisdiction